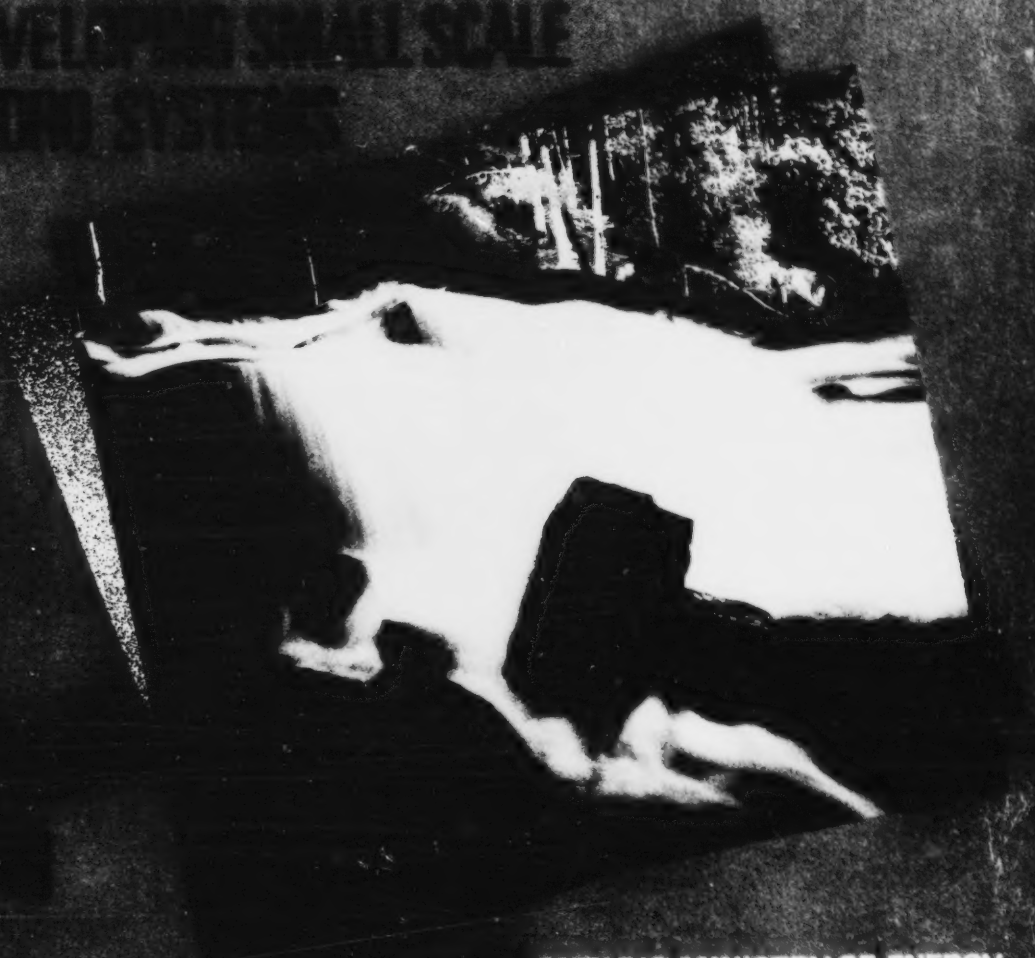
STREAMS OF POWER

DEVELOPING SMALL SCALE HYDRO SYSTEMS



ONTARIO MINISTRY OF ENERGY

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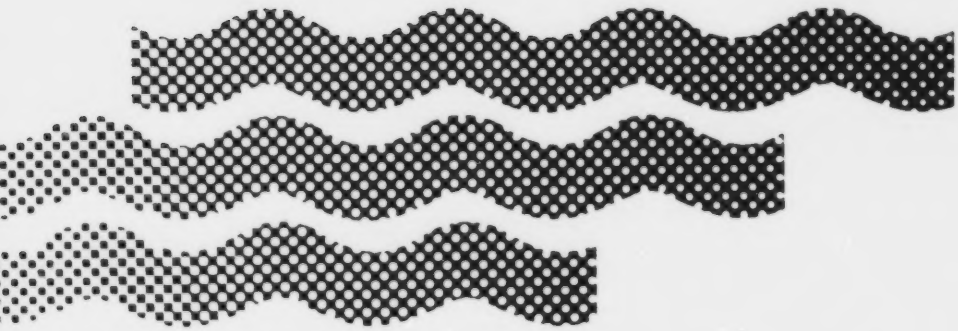

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INTRODUCTION

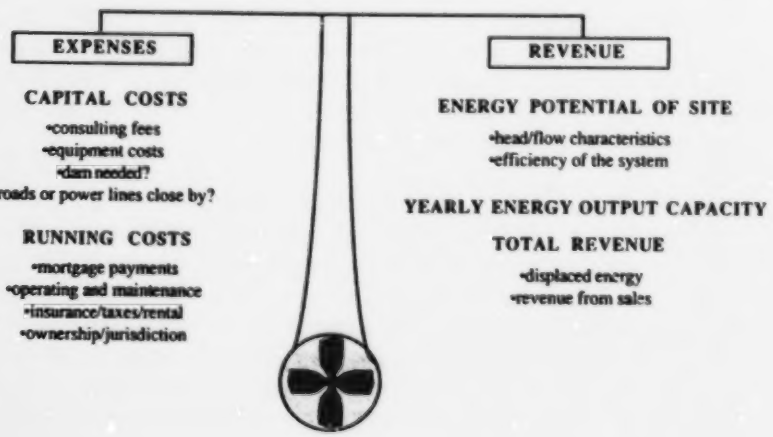
Full-scale development of the largest sources of water power throughout North America have been undertaken since the turn of the century. Yet even today significant amounts of hydraulic power remain untapped. Although it is not known how much untapped hydraulic power remains in Ontario, it is estimated that there is at least 500 MW (megawatts) at sites of 10 MW or less. This total would be enough to meet the needs of more than 100,000 homes if small-scale generating systems appropriate to such sites were installed.

The development of one of the smaller water power sites does not require the financial resources of a Crown corporation or utility. A 'micro' hydro installation by an individual for home use might cost as much as a new automobile. A somewhat larger 'small' hydro installation developed by a company or a municipality could range in cost from $50,000 up to $1 million or more, depending on the objectives and resources of the developer. Often what is needed is merely awareness by people with access to a possible site or an interest in such a project, that it may be an economically feasible venture.

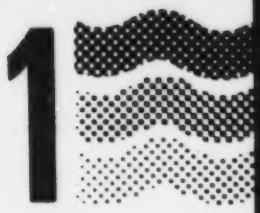
This handbook will help in the discovery of these opportunities. It introduces the reader to the world of small-scale hydroelectric

generation. It outlines the basic issues and considerations involved in planning a micro or small hydro system, and it describes, step by step, how to make a preliminary feasibility analysis of a possible installation. This handbook cannot tell you everything you need to know to do the job. But it can enable you to take an informed first look at the feasibility of a potential project.

The five parts composing the handbook approach the subject from different angles. First, the nature of the opportunities presented by small hydraulic sites in Ontario are described. Then the considerations involved in evaluating a particular site as a location for a plant are outlined. The third part describes the options available for constructing a commercial-scale plant at a larger site and shows how to analyse its economic feasibility. The fourth part covers the same topics for a very small, domestic-scale system. The final part outlines concisely the steps of the approval process to be followed in planning a small hydro system. The appendices present a number of useful sources of information for the developer wishing to proceed further in the examination of a possible installation.



Initial assessment requires balancing many factors. As figures become more focused there should be a detailed analysis of cash flow and an assessment of the net present value of the investment.



SMALL HYDRO IN NORTH AMERICA

RENEWED INTEREST IN AN OLD RESOURCE

Water power has always been an important energy resource in North America. Many towns and cities arose around waterfalls or rapids where dams could be constructed to provide mechanical power to run grist and saw mills, woollen mills, and foundries. With the spread of electrical lighting and machinery, water-driven turbine generators were installed at the dams to produce electrical power for the local communities. Indeed, much of North America's early rise to industrial and economic prominence can be attributed to the use of water power at sites across the continent.

The subsequent development of large hydroelectric and thermal generating plants with high-voltage, long distance transmission facilities, led to the creation of large-scale electrical distribution networks and a decline in the real cost of electricity. These power systems made smaller local hydroelectric stations uneconomical, and in the 1950's and 1960's they were taken out of service and dismantled. Often the dams and abutments were kept to maintain water levels for the recreational and residential uses that had come to depend on them.

Events of recent decades have directed attention once again to the economic potential of locally generated power. There has been a

dramatic rise in electricity consumption associated with its role in industrial development and residential space heating. To serve this rising demand, the large, central, hydroelectric generating stations have been supplemented by generation based on fossil fuels and nuclear power. In the 1970's, the real costs of all forms of energy, including electricity, began to rise rapidly. In some circumstances local resources may no longer be uneconomic to develop.

In most cases these sites are too small to be of interest to a major utility. Giving priority to installations that require its resources and are large enough to make a significant contribution to the regional network, most utilities will not normally seek to develop small water power sites. In Ontario, Ontario Hydro is not generally interested in sites when the average annual potential for power generation is less than 2000kW (kilowatts).

But the situation is changing and many utilities support the development of sites smaller than 2000kW. They offer information and advice to prospective developers as well as favourable conditions for purchasing any electricity that the developer wishes to sell.

An over-shot water wheel

Both public and private investors are examining the feasibility of restoring retired or obsolete plants and of developing new sites, often using existing dams. In some cases they are finding these options to be cost-effective. The projects being considered range in size from very small installations capable of supplying individual households to larger plants where generation at a community, small industrial, or commercial scale is contemplated.

This booklet is for people throughout North America to examine the feasibility of developing small hydroelectric generating plants. As this book was compiled in Ontario, many of the examples refer directly to that province. However, much of the data is applicable across the continent. Specific provincial utility policies are outlined in Appendix E ("Utility Policies on Private Generation in Canada").

New use of old site

AVAILABILITY OF SITES

Hundreds of sites capable of small-scale hydroelectric development are distributed throughout the continent. The Ontario government recently undertook an inventory of undeveloped water power sites in the province with potential to support small and micro hydroelectric generating systems of between 10 MW and 50kW capacity. More than 1000 such sites were examined. Almost all had existing dams, and those that did not could be developed without constructing one. (Information on these sites is on file at the Ministry of Energy.) In addition to the inventoried locations, many other very small sites exist with potential capacities that are below 50kW; more than adequate for individiual domestic systems.

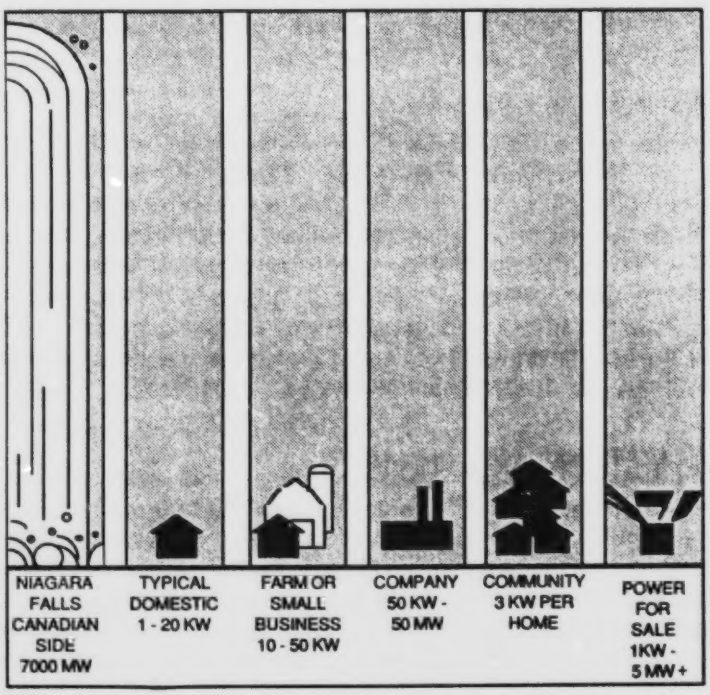
Small hydraulic sites present a variety of economic advantages. A few are located in or near communities not served by the major power network and could provide a cost-effective, environmentally sound alternative to diesel generation. Others are located within already serviced areas but could provide a less costly primary power source, with network connection offering not only backup security but also a market for sales of surplus power. Still others are near homes or businesses whose owners could benefit from reduced energy costs. Some are large enough to make feasible an installation whose purpose is the sale of electricity for profit.

Retired by Ontario Hydro in 1979, this site has been reactivated by private developers.

SMALL-SCALE PLANTS

Hydroelectric installations come in a vast range of sizes. The small-scale ones discussed in this booklet are usually classed in two groups: those with a capacity of 100kW or less are termed "micro hydro"; those with a capacity of 100kW up to 20 MW (200,000kW) are termed "small hydro". Installations larger than 20MW are known as medium and large hydraulic plants and are beyond the scope of this booklet.

Size and function are related. An independent individual system for domestic purposes would be the smallest of micro hydro plants; 4-8kW normally. To get an economic level of energy displacement in a community or industrial setting would probably require at least 50kW. A plant intended to produce electricity for profit would likely have to be at least 250kW capacity. However, these estimates are not definitive rules and should not discourage further investigation of a project that seems to fall between them.


NIAGARA FALLS CANADIAN SIDE 7000 MW
TYPICAL DOMESTIC 1 - 20 KW
FARM OR SMALL BUSINESS 10 - 50 KW
COMPANY 50 KW - 50 MW
COMMUNITY 3 KW PER HOME
POWER FOR SALE 1KW - 5 MW +

Energy production and use are a matter of scale.

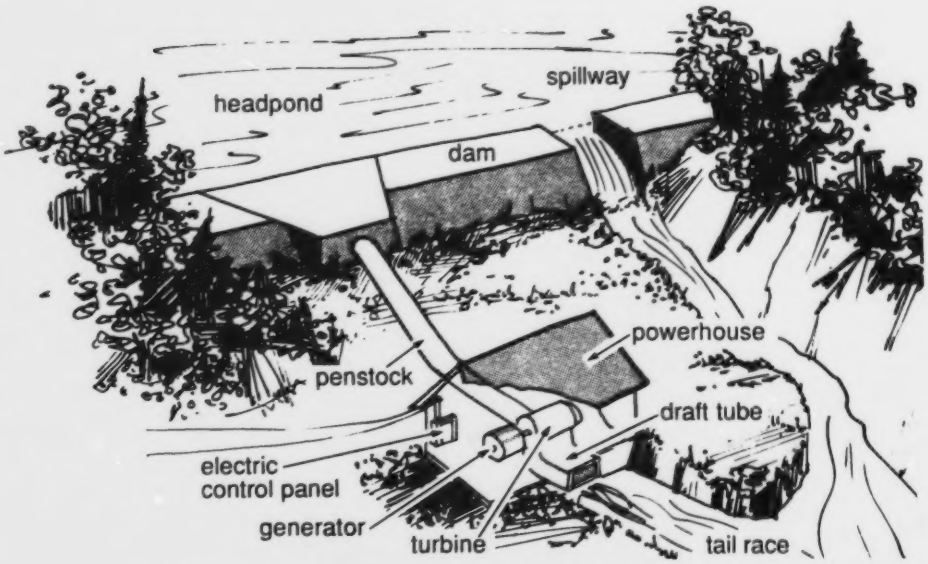
The dam and headpond are the most important features of a small-scale hydroelectric installation. Except for the smallest micro hydro installations, or for sites with unusual characteristics, a dam and headpond are ordinarily required. Their purpose is to ensure adequate,year round, submergence of the intake, which normally entails a water depth of a least two metres. If it is necessary to construct a new dam and create a headpond, the project's cost will be much greater and its environmental impact and legal implications much more significant. A site where they are already in place and no significant alteration of stream flow is needed, has notable advantages. The dam can be of the normal type with a spillway, or it can be a weir -- a low dam that allows a continual flow of water over the top. As mentioned above, hundreds of such sites exist in Ontario alone.

Some streams have a natural headpond above a waterfall or rapids. In these cases the intake can be submerged in the headpond and a pipe can carry the water down the natural drop to a generating station at the bottom. Sites that need no dam are rare and are usually less than 100kW. Some very large sites, for example, Niagara Falls, have no true dam, only a weir to direct water to the intake.

Hydroelectric installations of all sizes have other features in common. The **penstock** is a large pipe that carries the water from the intake down to the **powerhouse**. The powerhouse contains the **turbine**, the **generator**, and other **electrical equipment**. The falling water forces rotation of the turbine, which drives the generator. The electricity thus created is measured and adjusted by the electrical equipment before being fed into the system for use or into batteries for storage. The **draft tube and tailrace** direct the water that has passed through the turbine out of the powerhouse and back to the stream.

APPLICATIONS AND MARKETS

Small-scale hydro developers have a variety of purposes. The individual considering a $20,000 micro hydro system for a home or small business faces a somewhat simpler task than a company or municipality considering a $2-million small hydro system. Another difference exists between one developer contemplating a



complete electrical system able to operate independently of an external supply, and another who expects to remain connected to a utility for purchase and sale of power. Both size and independence have costs.

For the developer wishing to sell power on either a firm or surplus basis, the potential markets may be legally limited. In Ontario, if the location is within an enfranchized area (a municipality or a legally organized township), the only legal purchasers are the local public utility and Ontario Hydro. The municipality has the first right to purchase any power offered for sale. If it does not wish to do so, Ontario Hydro will buy the power subject to agreement on interconnection (Appendix E gives the 1986 rates), and resell the power to the municipality. The private developer cannot sell power directly to consumers.

Ontario Hydro serves rural areas directly. In these areas power can only be sold to Ontario Hydro. These restrictions do not apply outside unenfranchized areas, where a private developer can generate and sell power directly to consumers just as Ontario Hydro does. An example of such a system is the L & S Power Co. in the unorganized townships of Lyell and Sabine east of Algonquin Park.

ELORA MILL

LOCATION	Elora in Southwestern Ontario
SIZE	Capacity 140 kW Yearly output 1 million kWh
TYPE OF EQUIPMENT	Propeller turbine
COST	$320,000

Mr. Taylor installed a small hydro system at the Elora Mill Inn to offset his purchase of power. Some power is sold to the local utility.

GALETTA POWER CO.

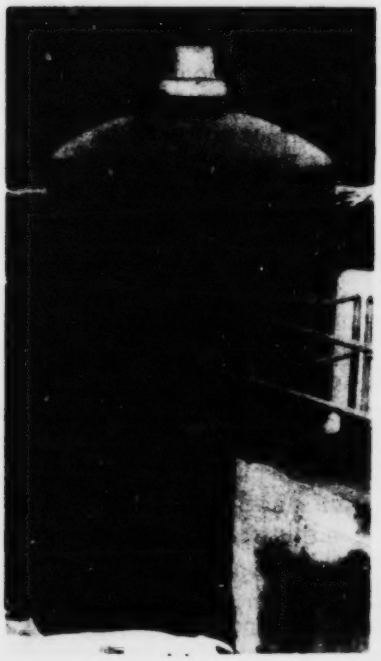
LOCATION	Galetta in Eastern Ontario
SIZE	Capacity 1000 kW Yearly output 7 million kWh
TYPE OF EQUIPMENT	Francis turbine
COST	Purchased in 1983 for $50,000 -- substantial extra costs incurred for rehabilitation

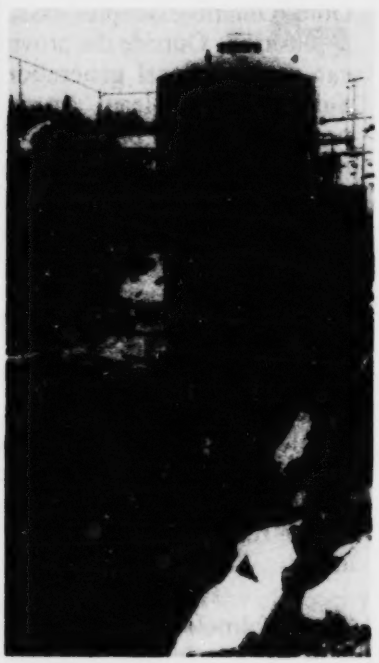
Mr. Dupuis purchased the retired small hydro station Galetta GS from Ontario Hydro. The plant has been improved and power is now sold to Ontario Hydro.

SANDAM

LOCATION	St. Thomas in southern Ontario
SIZE	Capacity 5.5 kW Yearly Output 40,000 kWh
TYPE OF EQUIPMENT	Little Giant Turbine (12"), AC generator

The turbine is about 100 years old and was salvaged north of Quebec City. The load is heating both hot water and space heat. A gate is opened when power is called for.





SULTAN

LOCATION	The town of Sultan in northern Ontario
SIZE	Capacity 150 kW Yearly output 1 million kWh
TYPE OF EQUIPMENT	Vertical Francis turbine "mini-hydel"
COST	$250,000 (equipment)

This small hydro plant provides power, with diesel backup, for the community of Sultan. This community is remote from the Ontario Hydro electrical grid. The small hydro plant was paid for by the provincial government and is operated by Ontario Hydro.

Other Ontario examples exist of every type of small-scale hydro application. Outside the provincial power network, the installation can replace diesel generation, as in the remote community of Sultan near Chapleau. Another concept is to displace purchased power (except for peaks) and to sell surplus power to the network in off-peak hours, as is done at the Elora Mill in Elora. The developer can even set up a plant whose sole purpose is to sell power to Ontario Hydro, as is done by the Galetta Power Co. near Arnprior.

The developers foresee a variety of benefits from these projects. What makes a hydroelectric system economically attractive is the fact that annual energy costs are very low for the lifetime of the installation. An independent system of this type can provide the developer with a secure supply of energy at a price that is protected from inflation and actually declines with time as the capital cost is paid off. Moreover, in many regions, energy costs can be reduced further by selling surplus electricity to the local utility.

Since hydroelectricity is an indigenous, renewable energy source with no emissions, the development of small-scale hydro systems is in harmony with national and local energy goals. In Ontario, public encouragement to developers is provided in many ways. A federal tax incentive now under review in the form of a Class 34 exemption allows the full capital cost of such a project to be written off in three years: 25 per cent the first year, 50 per cent the second, and 25 per cent in the third year. Ontario Hydro will cooperate with advice on rates, operating standards and safety, equipment, and other technical matters. Small hydro projects may also be eligible for Small Business Development Corporation (S.B.D.C.) investments. If the project is owned by an S.B.D.C. the Ontario Government will provide 30 per cent of the required equity. The Ontario Ministries of Energy and Natural Resources will advise the developer on the approvals process, financing and other matters. This handbook introduces the host of public and private sources of information available to help the potential developer get started.

2

EVALUATING THE SITE

NATURAL SUITABILITY

The distance from the site to the point of use of the electricity must be considered because power is lost in the course of transmission. The Canadian Electrical Safety Code states that this loss cannot exceed 5 per cent. Steps can be taken to limit power loss in transmission, such as using larger wires or stepping up the voltage to reduce the current. But these measures increase costs.

The smaller the system, the greater the distance constraint. For a commercial small hydro system of 250kW, the cost of transmission poses less of a burden proportionally than it does for a domestic micro hydro system of a few kilowatts. The latter can afford to ignore transmission power loss only if the distance from generator to user is about 30 metres or less. At greater distances it will affect the design to an increasing extent. At more than several hundred metres the cost of compensating for transmission loss from generator to house can affect the feasibility of a domestic system.

Another characteristic of a suitable site is that it experiences a solid ice cover in winter. A potential source of real trouble to a micro hydro installation is that caused by ice crystals in the water (frazil ice) that cling to the intake and accumulate to block the flow of

water. This problem is minimized at a site that normally acquires a solid ice cover early and retains it until spring breakup.

Streams in areas with very cold winters may freeze to the bottom and pipes carrying the water may also freeze. Pipes of less than 30 cm in diameter may be susceptible to freezing, especially if the small hydro station is shut down and water is allowed to stand in the pipes.

Finally, a site requiring the construction of a new dam is at a disadvantage. The creation of a headpond and the resulting environmental impact will entail much negotiation over proposed designs with public authorities and with other users of the stream. The additional costs of design and construction are likely to significantly affect the estimated feasibility of the project. In fact, the Ontario government does not encourage construction of new dams for small hydro purposes except in areas not served by the provincial power network. Thus a site with an existing dam -- though it may require repair -- or a site that provides adequate intake submergence without a dam are most likely to prove feasible.

The suitability of an existing dam may be one of the earliest concerns for which the developer will seek expert advice. Advice may be provided by a consulting engineer or may be available from a government source. Visual inspection may be followed by a review of the original design criteria, the construction drawings, and the instrumentation and maintenance records. Collection and analysis of structural samples, hydrologic and geotechnical investigations, and calculations of stresses and safety factors should also be involved. Often restoration will be needed, such as remedial work to the foundations, repair of deteriorated portions of the dam and spillway, possibly increases in spillway capacity and in usable head, and control of stream flow during the restoration itself. However, the cost of these activities will usually be only a fraction of the cost of building a new dam.

HYDRAULIC POTENTIAL

Developers should make a rough estimate of the energy potential of a site at an early stage in their consideration. If preliminary

indications are favourable, more accurate estimates will be possible later based on precise measurements of stream flow, details of layout and design, and data on turbines, generators, and other equipment.

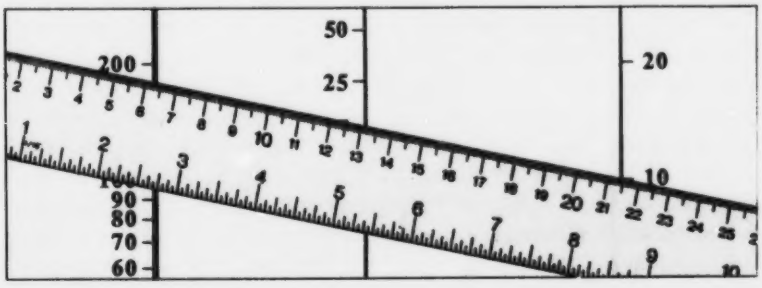
The energy potential of a water power site depends on the **flow** and the **head**, as well as the **efficiency** of the generating system. The flow is the quantity of water in the stream per unit of time passing a point; that is, the amount of water and its speed. The head is the vertical distance through which the water falls; that is, approximately the distance from the surface of the headpond to the level of the tailrace. The efficiency of small-scale hydro generating systems in converting water power to electrical energy varies from 40 to 85 per cent, but in most cases an efficiency of 70 per cent can be used for preliminary estimates.

The usable hydraulic potential of a site can therefore be calculated with the following equation:

$$P = \frac{Q \times H \times e}{102}$$

where P is capacity in kilowatts, Q is flow in litres per second, H is the available head in metres, e is efficiency in percentage, and 102 is a derived constant. In addition, the nomograph in Figure 1 allows a quick correlation of head and flow to estimate power.

The nomograph is designed so that a straight edge, positioned at the figures corresponding to the head and flow of the potential site, allows the power output to be read from the middle column. In the example shown, a flow of 190 litres per second and a head of 10 metres gives an estimated power output of 13kW.



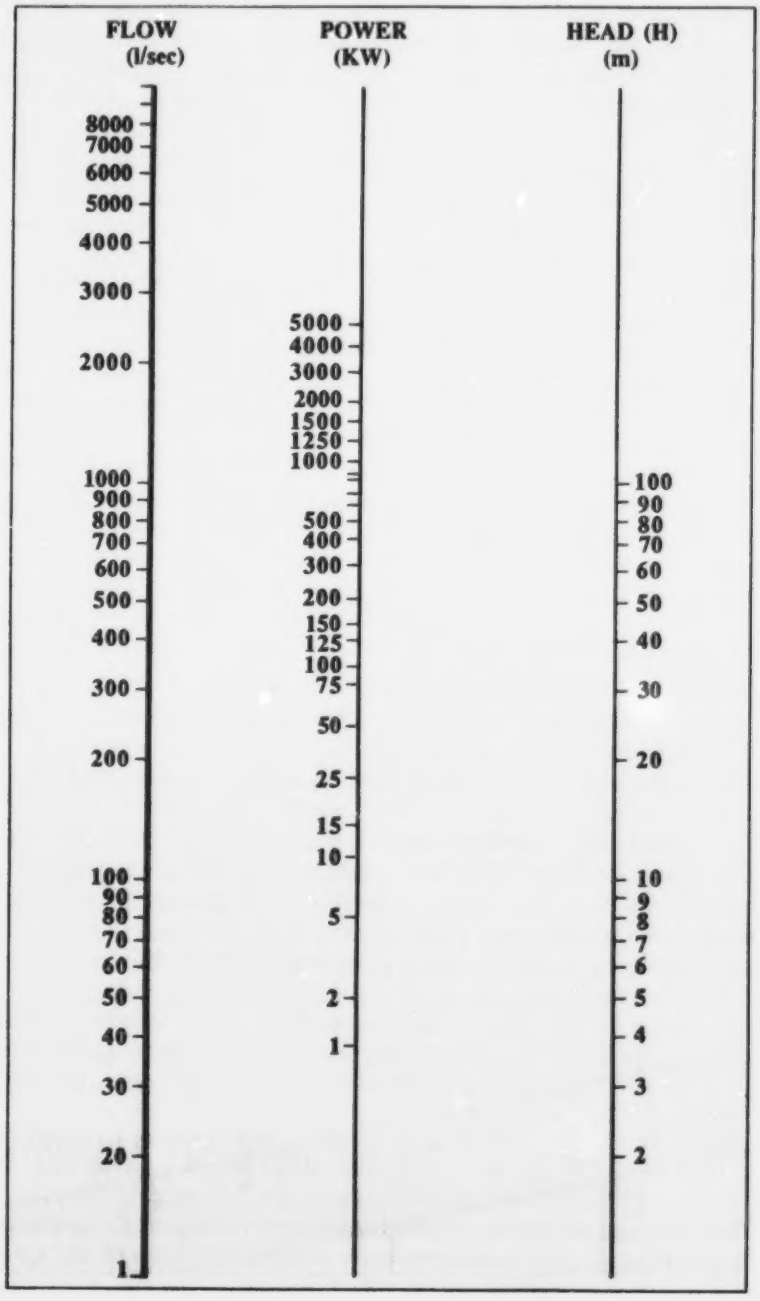


FIGURE 1
Nomograph for determining power from the head and flow

The uncertainties involved make it advisable to undertake several estimates with varying data and assumptions. The developer may measure both the flow and the head at the site in several ways. Methods of measuring the flow and head at a site are described in this booklet (Appendix A). With these different data sources and with different suppositions as to the range of the variables, the probable potential of the site can be assessed with increasing confidence.

Flow changes continually. Hourly and daily changes affected by rainfall and runoff are superimposed on seasonal changes. In southern Ontario, rivers and streams are at their highest levels in early spring and at their lowest levels during late summer. In northern Ontario, the smaller rivers and streams are usually at their lowest levels in mid-winter. These variations must be considered in the estimates. For example, when on-site measurements are possible, a minimum of five measurements in twenty-four hours for a minimum of five days taken at least two times in the year are advisable. The data collected should be sufficient to allow an estimate of the daily flow that can be relied on for each month.

From this information a Flow Duration Curve (Figure 2) is derived for use in refining the estimate of hydraulic potential and for sizing the turbine and generator. (The derivation of a flow duration curve from flow data is described in Appendix B.) The curve shows the percentage of the time that any flow is available. For example, in the stream shown in Figure 2, a flow of 100 litres a second or more occurs 50 per cent of the time in an average flow year.

The curve is used to decide the "Design Flow" for which the turbine will be selected. If the system is to be independent of any utility backup, the design flow should be that which is available 95 per cent of the time. For an interconnected system, where utility backup exists and sale of surplus power is a goal, the design flow can feasibly be lower, and even down to 50 per cent in some cases. If the sale of "firm capacity" -- guaranteed power availability -- to a major utility is contemplated, rate structures suggest the design flow should be available about 70 per cent of each month for at least ten months of the year. For this estimate, and to refine other estimates, a series of monthly flow curves is highly desirable.

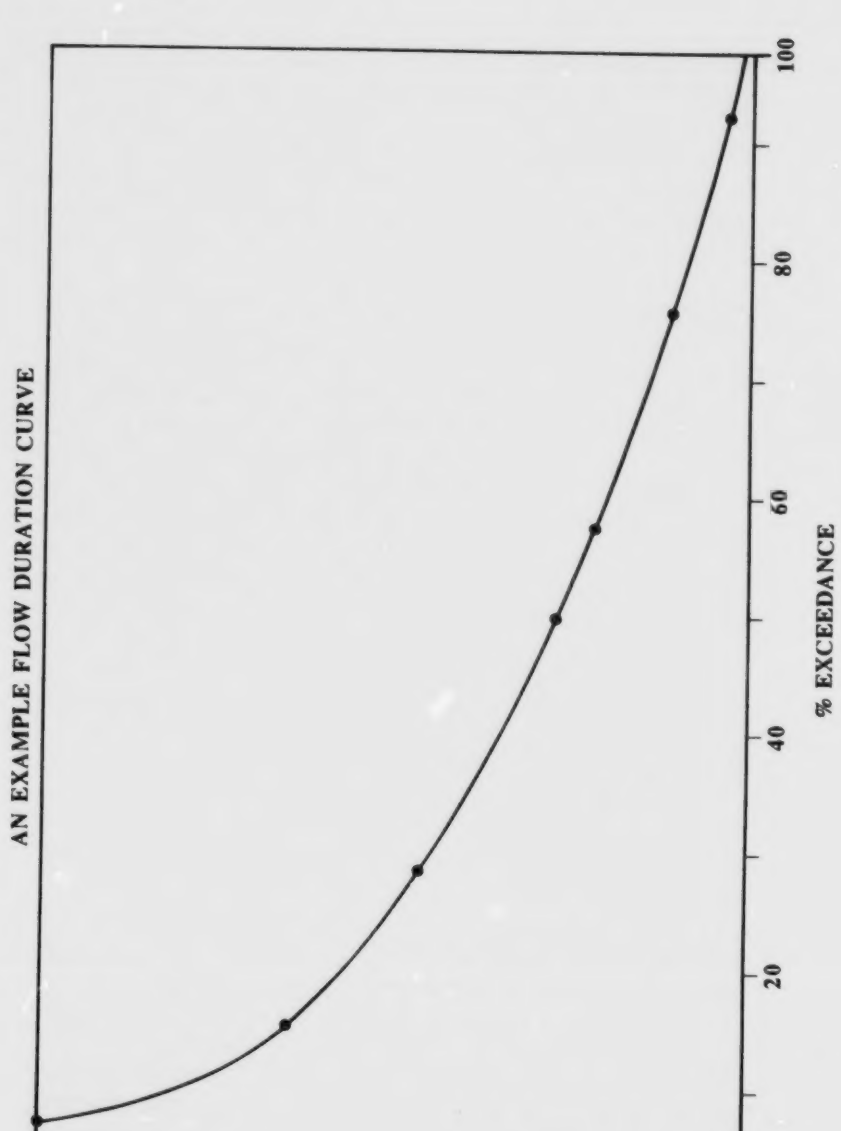

AN EXAMPLE FLOW DURATION CURVE
FLOW (LITRES/SEC.)
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
20
40
60
80
100
% EXCEEDANCE

FIGURE 2

An assessment of hydraulic potential sufficient to give a reliable estimate of the design flow will be made on the basis of these extended on-site measurements, allowing considerable refinement of the first rough estimates. Awareness of the extent of these refinements is a useful guide to the developer in making those early calculations.

In Ontario, the Ministry of Natural Resources may have on record an estimate of the power potential of the site. (Inquire at the Conservation Authorities and Water Management Branch; (416) 965-6287.) Stream flow records are maintained for many Ontario rivers and streams, and this information may be obtained from Environment Canada (25 St. Clair Avenue E., Toronto, Ontario, M4T 1M2; (416) 966-5624), or from the nearest district office of the Ontario Ministry of Natural Resources (See Appendix F).

OWNERSHIP AND DEVELOPMENT RIGHTS

A site being considered by a small hydro developer will consist of the bed of the stream, including the headpond if any, and some adjacent land usually on both sides. The land composing the site will be one of three types: entirely private land, entirely Crown land, or both private and Crown land. (Note: Crown land refers to land held by the provincial or federal government.) The requirements for gaining development rights vary accordingly. In particular, where Crown land is involved development rights must be leased from the Crown in the form of a **Water Power Lease** (see Chapter 5.4). If the headpond, flooding, powerhouse construction, or access will extend onto Crown land adjacent to the stream, a **Licence of Occupation** also must be obtained.

Entirely Private Land

Sites entirely under private ownership are usually found only on very small streams. In Ontario, the beds of navigable watercourses -- those large enough for commercial or recreational boating at average flow -- are owned by the Crown. However, if

the stream is not navigable and both banks are owned, the bed of the stream belongs to the owner and water power can be developed. Since these are small streams the hydraulic potential would normally be appropriate for domestic micro hydro systems.

Water power development rights at sites on larger streams may also be held privately. These situations occur when the original letters patent by which the land was acquired from the Crown expressly grant to the owner either the bed of the stream or the right to develop power from the stream, for example to run a mill. However, no grants of this kind have been made in Ontario since 1914.

Where an entire site is privately owned, no leases from the Crown are required. At such a site, the government's involvement in a hydraulic development is as described in Chapter 5, The Approvals Process.

Entirely Crown Land

If the site is on Crown land, the developer must obtain the right to develop the site from the responsible government department. Where federal Crown land is involved, information on the acquisition of water power development rights will be available from Parks Canada. If provincial Crown land is involved, the provincial Ministry of Natural Resources has administrative responsibility. This handbook outlines the provincial requirements for Ontario.

Regardless of who initiates interest in a potential water power site on Ontario Crown land, the Ontario government will take certain steps. If the site has a potential average annual energy capacity greater than 2 MW, Ontario Hydro will be given three months to exercise a right of first refusal. If the site is smaller than 2 MW or if Ontario Hydro is not interested in it, the Ontario Ministry of Natural Resources will publicly invite competitive proposals for its development, including tenders for rent of land and any Crown facilities on the site. The proposals will be evaluated according to stated criteria and the successful one selected.

The chosen developer then negotiates a lease authority with the Ministry of Natural Resources. This lease authority may incorporate a Water Power Lease Agreement, a Licence of Occupation, or both depending on the situation which will vary according to size of operation, flooded area, commercial ability and other factors. If the installation has a capacity of more than 100kW, the water power rental is based on the amount of power produced and is calculated using a formula which is adjusted annually up or down according to the Consumers Price Index. With installations smaller than 100kW, rent is charged only for Crown-owned facilities used and Crown land occupied. The 1985 annual water rental rate is $5.50 per annual average horsepower or $7.37 per annual average kW. The developer will also pay an annual rental at fair market value for occupation of the land and possible use of Crown owned facilities.

Both Private and Crown Land

Where both private and Ontario Crown land are involved -- with the bed of the stream commonly belonging to the Crown -- the Ministry of Natural Resources offers the site for development first to the landowners. If none of them are interested but all are willing to deal with a developer, the Ministry once again publicly

The ownership and rights of both the banks as well as the stream bed have to be determined.

invites competitive proposals, making it clear that the proponents will have to negotiate with the owners for rights to use their land. If any of them oppose development, the project will probably stop. The government requires the written consent of every private landowner involved to the proposed development and to the arrangements made for use of private land. Unless the Crown owns land adjacent to the stream, no Licence of Occupation will be required and only a Water Power Lease negotiated.

3

EVALUATING A COMMERCIAL-SCALE SYSTEM

INTRODUCTION

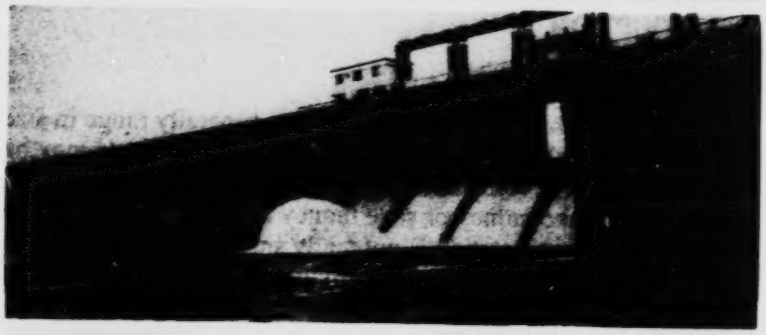
Commercial-scale small hydro plants generally range in size from 250kW to 5 MW. Smaller and larger plants may be practical for some developers. The key is that they should either make money or save money in the long run. Even a 250kW small hydro station is not really small. The cost could be $500,000 and heavy construction equipment is needed for installation.

Developers interested in installing a small hydro plant to make money will first need to acquire a good site (see Chapter 2). Financing, government approval and a contract for the sale of power to the utility are the other milestones in the successful development of a site for the sale of power.

Commercial enterprises that are adjacent to a potential small hydro site, perhaps a site that once provided power to a forerunner of the enterprise, can develop the site to reduce their power bills. In these circumstances the site is often already owned by the enterprise and its use established; therefore acquisition and approval are essentially complete. Economic feasibility and financing of the small hydro plant remain. The utility approves the electrical component of the installation. If sale of surplus power is intended, a contract for the sale of power will be needed.

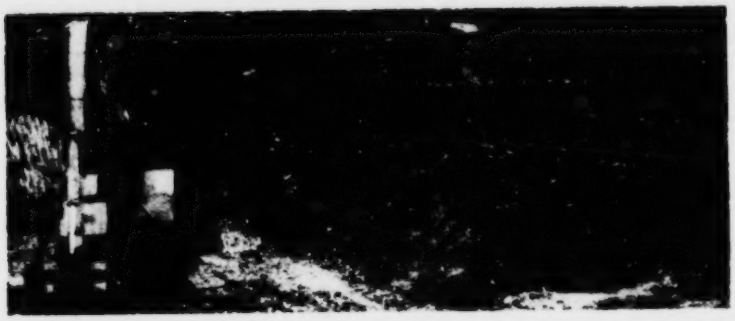
At the initial stage, information on the site can be obtained from various government sources. Across Canada, this includes the Department of Energy, Mines and Resources. In Ontario the Ministry of Natural Resources, the Ministry of Energy and the local Conservation Authority can provide information. The utility should be contacted early in the process to obtain its rates and requirements for interconnection. A commercial-scale system will usually require a feasibility study by a consulting engineer before the final decision to proceed can be made. If the developer has already chosen an equipment manufacturer, the manufacturer can be approached to do the feasibility study.

FANSHAWE

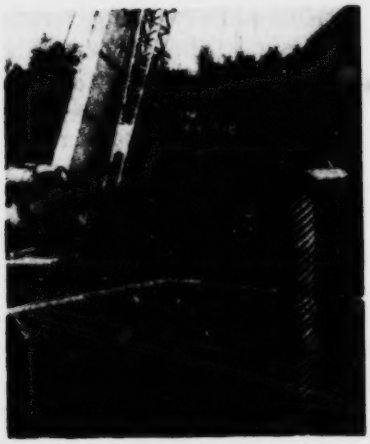


Fanshawe Dam showing original side discharge

side discharge with penstock attached

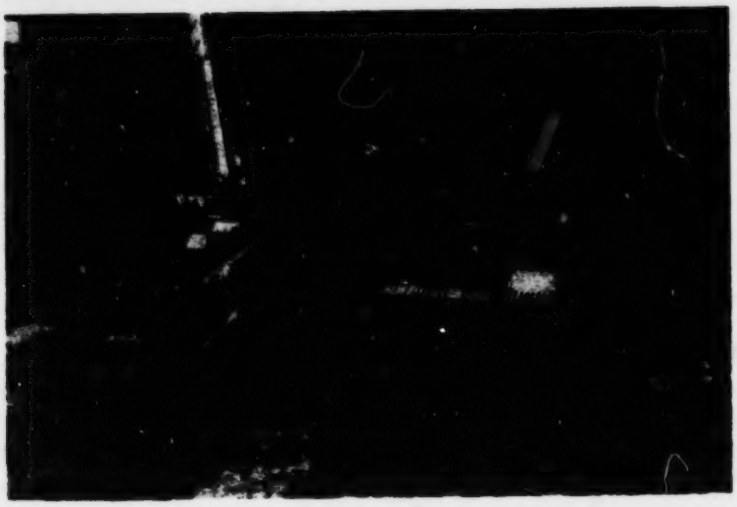


excavation for tailrace and powerhouse



***Left** installing the penstock*

installing the turbine



turbine and penstock in place

DESIGN AND EQUIPMENT

The flow of water at the site changes continually, as discussed earlier. Smaller streams being used in a small system vary hourly, daily, and seasonally. The developer must choose the hydroelectric generating system that will make the best use of the available water. Assistance in this task is available from equipment manufacturers.

As background, the two basic issues are described here. The first decision is the type of generating system required. The second is how big it should be, which can usually be resolved by determining the size that gives the best long term return on investment.

Generating System

There are several ways to produce the steady 60-cycle alternating current (AC) that will almost certainly be required by consumers. The methods are not equally applicable to commercial-scale systems.

One way is to generate direct current (DC) and convert it to AC by means of an "inverter". This approach does not require generator speed to be controlled and also allows any excess energy produced to be stored in batteries. However, there are major disadvantages with this approach. The cost of battery storage at present prevents it from being a feasible option except in very small, domestic-scale micro hydro systems (see Chapter 4). Moreover, inverters are costly, consume power themselves, and are limited in their ability to handle the surge demands that occur when electrical equipment and appliances are turned on. Therefore, it is unlikely that DC generation will prove feasible for a commercial-scale small hydro system.

A second way to generate AC is to use an "induction" generator interconnected with the local utility system. The system current will ensure that the generated current is compatible, eliminating the need for additional electrical equipment. Since the alternating frequency is determined by the system current rather than by the

generator, it (frequency) is not sensitive to rotation speed. The induction generator itself is relatively inexpensive and is essentially an electric motor equipped to run overspeed. However, the system is a "slave" to the utility; it cannot operate independently. If network power fails, generation ceases. This approach may be suitable if the system is intended to supply power for sale to the utility or to displace some network power. But it will not do if the system must be able to supply power independently or to supplement a small local system such as diesel generator.

The third way to generate AC is to use a "synchronous" generator. This does not require an external power source to produce electricity. A system of this type can operate on an independent basis as a sole source of supply in isolated areas. However, the frequency will vary with the generator rotation speed; therefore, speed must be carefully controlled. In such systems a mechanical governor is commonly used that senses the rotation speed and activiates intake gates or a blade pitch mechanism to hold the speed constant. Control equipment is required for regulating the voltage and phase characteristics of the current to the standards required by consumers and for synchronizing the system with another if interconnection is to be an available option. Clearly the use of a synchronous generating system is the most complex and costly alternative and requires the most careful selection and coordination of equipment.

In many cases the developer will have little freedom of choice about the basic type of generating system. At a commercial scale, DC generation will probably not be cost-effective. If the system is to be isolated from utility networks, a synchronous system is best. If the sale of power to a utility or the displacement of some portion of purchased power is the goal, a dependent system based on an induction generator will be the most advantageous. (Technical considerations may place restrictions on the use of large -- more than 500kW -- induction generators. This question should be discussed with the utility.)

Meeting Demand

For a dependent, induction generating system the pattern and level of demand will be of minor significance if the utility can accept all

the power the site can produce. The goal will be to size the installation to maximize cost savings from displacement of electricity purchases or to maximize profits on sales of electricity to the utility. The approach will be to examine the utility's rates for sale and purchase with particular attention to special rates for firm capacity. Since firm capacity is more costly, sizing the generator to displace such blocks or to provide them for sale is desirable. For example, Ontario Hydro now pays 43% more for capacity that is available at least 65% of the time each month. A generator sized to provide that capacity availability, in view of the site's flow duration curve, will likely be more profitable than a larger generator.

For an independent, synchronous generating system, the pattern and level of demand to be served are more significant. If the hydraulic potential of the site is smaller than the demand peaks in the system, provision will have to be made for meeting those peaks, either with additional peak generating capacity, such as a diesel generator, or with conservation and load management techniques, such as service restrictions and prohibitions. The hydroelectric component can be sized to minimize costs over the system as a whole.

If the hydraulic potential of the site exceeds the demand peaks in the system, other options exist. One is a combined system with added peaking capacity as described above. Another is to build to meet the peaks with water power. In off-peak hours the generator will then have extra capacity, to be handled either by controlling the amount of water reaching the turbine using a mechanical governor or by a "dump" load. With a dump load, the power available in excess of demand is fed into supplementary water and space heating. This approach is often more cost-effective than undersizing the hydraulic generator or incorporating a costly governor.

Electrical control equipment is a basic requirement in any generating system. It is needed to ensure that startup, operation, and shutdown conditions are kept within predetermined limits. For a system interconnected to a utility, the requirements include synchronization equipment -- unless an induction generator is used -- and several types of automatic and manual circuit breakers and disconnection devices. In addition, equipment is needed to

maintain the "quality" of purchased power: voltage, frequency, flicker, harmonics, and power factor. The utility itself will supply information on these requirements. For an independent system, besides the quality control devices, minimum protection requirements would shut down the system under the following conditions:

- overspeed -- from governor failure or loss of electrical load
- overvoltage -- from regulator failure
- undervoltage or underspeed -- from overloads
- overheating -- from loss of oil pressure.

Programmable controllers that can perform many of the control functions automatically are available at relatively low cost.

Turbine Design

Many types of hydraulic turbines have been invented to extract power from water (see Appendix C). The developer, therefore, has a choice to make. In evaluating the possibilities, a basic practical issue and a basic theoretical issue should be considered.

The basic practical issue is the compatiblity of the turbine structure to the layout of the site. The shape, excavation, and foundation requirements of one type may be much less suitable than those of another when the configuration of the dam and any other existing facilities are considered. Information on the civil requirements of turbine installation will be available from the turbine manufacturers.

The basic theoretical issue is the efficiency of the turbine at different power inputs. A particular turbine will have its own design flow and power output at which its efficiency is highest. At their best, turbines tend to be much alike, with peak efficiencies of 85 to 95 per cent. Where they differ is in their efficiencies at other flows and power outputs. Generally speaking, the better a turbine is at maintaining its efficiency across the range of flows and power outputs, the more expensive it is. The question is how much of this flexibility the developer needs.

The advantage of greater flexibility is that it allows the developer to capture more of the full hydraulic potential of a site. As the flow in a stream declines below that for which the turbine is

designed to develop its rated power output, the output of a less flexible turbine drops more rapidly than the output of a more flexible turbine. Thus the constant power output that the stream can be relied on to produce for, say, 80 per cent of the time will be greater with a more flexible turbine. Whether the difference is enough to justify the additional cost of the more flexible turbine is for the developer to decide.

A second major difference between turbine types is that some are best for high heads, others for low heads. "Impulse" turbines such as the "Pelton Wheel" require high heads (usually over 35m) to create high water pressures. These turbines are driven by the striking force of water; therefore, their speed of rotation is limited by the water velocity. "Reaction" turbines such as the propeller turbine are suited to low heads because, with blades that deflect the flow rather than intercepting it, they can rotate faster than the speed of the water itself. Thus the head as well as the flow helps determine the turbine design. Most Ontario small hydro sites -- though not all -- have a low head, and reaction turbines will usually be selected.

ECONOMIC ANALYSIS

The economic feasibility of the project will be of central interest to the developer. Preliminary estimates will be used at the beginning to decide whether the concept is even worth considering. As more accurate data becomes available about the site and the cost of equipment, the estimates can be refined to provide guidance in evaluating options. In some cases the feasibility will be unequivocal; in other cases it will be sensitive to assumptions about costs, revenues, and future rates. The following section describes the features of a comprehensive economic analysis of a project.

In broad terms the critical issues may be simply stated. With a small hydro system the operating costs are very low because unlike other energy sources, there is no charge for fuel. The financial question is whether the revenues will more than cover the cost of the capital investment. The revenues consist of the value of any purchased energy displaced and the value of any energy sold. These values will rise with energy costs and inflation over

the long term. The cost of the investment is essentially a fixed annual mortgage cost that terminates after a certain number of years. When the mortgage is paid off, the annual revenues would normally exceed annual costs many times over. Furthermore, with proper maintenance, the lifetime of well-chosen equipment should be 40 years or more, allowing lengthy amortization periods and prolonged operation after the loan is paid off.

The economic analysis described here has three stages:

- estimating annual costs -- annual mortgage, annual operating
- estimating annual revenues -- energy displaced and sold
- cost benefit analysis based on cash flow and net present value.

This approach provides a convenient and reliable basis on which the developer can compare alternatives. Its application is illustrated by two examples presented in Appendix D.

Estimating Annual Costs

The annual costs are placed into two categories: mortgage payments covering the capital, and operating expenses.

Capital Cost and Annual Mortgage Payments

The estimated capital cost consists of the direct and indirect costs of construction. The direct costs are those of the equipment and physical structure, such as the dam, penstock, turbine, generator, control equipment, tailrace, and powerhouse. The indirect costs are the non-physical costs of the installation, such as engineering and consulting fees, financing costs, and an additional contingency cost. The financing cost is the cost of interest on the funds used during construction, which is usually added to the capital cost and amortized with the loan. A contingency cost is usually assumed as an additional 15 per cent of direct costs for unforeseen expenses in installation. Even the earliest estimates on the project should consider all these aspects of capital cost. Later estimates will be based on more precise data.

When the amount of the loan required to cover the capital cost has been determined, the annual mortgage payment can easily be

calculated with the use of Table 1. The table gives "interest factors" for several interest rates and lengths of amortization. For example, a mortgage at 14% interest at 10 years amortization has an interest factor of 5.2161. To find the annual payment required, divide the amount of the loan by the interest factor. Therefore, if the mortgage mentioned previously is for $40,000, the annual payment will be 40,000/5.2161, or $7668.56.

TABLE 1

INTEREST FACTORS FOR MORTGAGE RATES

Number of years	INTEREST RATES 10%	12%	14%	16%	18%	20%
1	0.9091	0.8929	0.8772	0.8621	0.8475	0.8333
2	1.7355	1.6901	1.6467	1.6052	1.5656	1.5278
3	2.4869	2.4018	2.3216	2.2459	2.1743	2.1065
4	3.1699	3.0373	2.9137	2.7982	2.6901	2.5887
5	3.7908	3.6048	3.4331	3.2743	3.1272	2.9906
6	4.3553	4.1114	3.8887	3.6847	3.4976	3.3255
7	4.8684	4.5638	4.2883	4.0386	3.8115	3.6046
8	5.3349	4.9676	4.6389	4.3436	4.0776	3.8372
9	5.7590	5.3282	4.9464	4.6065	4.3030	4.0310
10	6.1446	5.6502	5.2161	4.8332	4.4941	4.1925
11	6.4951	5.9377	5.4527	5.0286	4.6560	4.3271
12	6.8137	6.1944	5.6603	5.1971	4.7932	4.4392
13	7.1034	6.4235	5.8424	5.3423	4.9095	4.5327
14	7.3667	6.6282	6.0021	5.4675	5.0081	4.6106
15	7.6061	6.8109	6.1422	5.5755	5.0916	4.6755

Annual Operating Expenses

The operating expenses of a small hydro facility consist of operating and maintenance costs, insurance fees, water power lease rental (if any), property taxes, and general or administrative expenses. A figure of 1 to 2 per cent of capital cost can be used to represent operating and maintenance costs. Insurance is purchased to protect the owner from the loss of the facility through fire, theft, or vandalism. Additional property taxes must be paid on the increased value of the property arising from the installation of equipment. General and administrative costs include any legal or accounting costs associated with the project.

Estimating Annual Revenues

Revenues arise from the cost savings resulting from the displacement of power that would otherwise have had to be purchased from a utility, as well as from actual external sales of power. The estimate of revenues therefore must begin with an estimate of the amount of electricity the installation will produce for displacement and sale. It must also be based on the rates at which electricity is bought and sold by the local utility.

Two considerations are involved when electricity is bought and sold. The rates are based either on just energy (measured in kilowatt hours) or on both energy and capacity (measured in kilowatts). A commercial electrical bill, for example, contains two charges. The capacity charge is for the maximum amount of power that has been drawn from the wires during any one hour interval over the billing period. The energy charge is for the total amount of electricity actually used over the billing period. Thus a 100-watt bulb has a capacity of 0.1kW, and if it burns for 10 hours it uses 1kWh of energy. In this way the same amount might be charged to two companies, one of which used a lot of power occasionally while the other used less power continuously.

The concepts of capacity and energy apply to all electrical systems, including small hydro installations. So far we have considered mainly capacity (or "power") expressed in kilowatts or megawatts, because that is what governs the size and cost of the installation and therefore the amount of the investment. However, when we turn to examine the proportion of the year that the flow will allow the power to be available, or that the power will be used for displacement or sale, the criterion is different. We are looking not only at the capacity of the system but also at the energy that will flow from it. Revenues can be affected by both aspects.

Annual Energy Output

To calculate the annual energy output of the plant it is necessary to estimate the proportion of the time it will be generating power, taking into account shutdowns for maintenance or inadequate flow. The flow duration curve of the site will be of assistance in estimating the "capacity factor". The annual energy output is

therefore the power of the generator (kW), times the number of hours in the year (8760), times the capacity factor. For example, a 200kW plant with a capacity factor of 0.75 (that is, it will be operating 75 per cent of the time) will have an annual energy output of about 200 x 8760 x 0.75, or 1,314,000kWh.

Cost Savings from Displacement

Internal consumption of electricity from the hydro plant will allow the developer to avoid purchases from a utility. As discussed above, the cost of those purchases would probably have been based on both energy used (kWh) and a capacity charge (kW). Both should be included in the estimate.

The energy component will be the annual energy output from the hydro plant (or that portion of it used internally and not sold), times the electrical rate charged for that amount.

The capacity component will be subtracted from the utility's capacity charge. Thus if the developer's internal needs are 300kW firm capacity, and the small hydro plant provides 200kW for nine months of the year, then the capacity charge from the utility can be reduced to 100kW for nine months and remain at 300kW for three months. This saving is combined with that on energy consumed to consitute an estimate of the savings portion of total revenues.

Revenues from Sales

An estimate of the value of sales must be based on the utility's rates for purchase of energy, and firm capacity. The rates offered by Ontario Hydro are always available to any private developer. Ontario Hydro's rates for 1985 are presented in Appendix E. The same principles apply as in estimating savings from displacement. The best price (3.3¢ per kWh in 1985) is offered for power available at least 65 per cent of the time in any month. The incentive to the developer to operate at a capacity factor of 65 per cent, or greater, is clear.

Cost Benefit Analysis

At this point we are in a position to compare the costs and revenues for the first operating year of the plant's lifetime.

However, with a hydroelectric plant such a comparison can be very misleading because it is a long-term investment whose financial position improves with time. A more balanced picture is obtained by forecasting the accumulation of costs and revenues with time and basing the comparison on a longer view. This next step can be done by a cash flow analysis over a number of years followed by a translation of the accumulated expenses and revenues into net present value.

Analysis of Cash Flow

A simple spreadsheet operation reveals how profits and losses accumulate a year at a time. The analysis is driven by two assumptions: an assumed annual increase in electricity prices (which raises revenues) and an assumed annual inflation rate (which raises operating expenses). Although revenues are combined, operating expenses are distinguished from mortgage payments. For each year total expenses are subtracted from total revenues to give annual profit (loss), which is then added to an accumulating profit (loss) total. It is recommended that the analysis extend at least five years beyond the expected year of mortgage termination.

The table that results will have 15 or 20 rows or more (one row per year), if the mortgage is for 10 or 15 years or more. It will contain the following six columns:

A: Total revenues (previous A + electricity price increase)
B: Operating expenses (previous B + inflation rate)
C: Mortgage payments (constant each year)
D: Total expenses (B + C)
E: Total profit (loss) (A - D)
F: Accumulated profit (E + previous F).

For year 1, A to D are entered as estimated earlier, and E and F are calculated. For Year 2, A and B are raised as assumed, C is held constant, and D to F recalculated. (See examples in Appendix D.) This is done a year at a time until at least five years after the mortgage amortization period.

The table will show that revenues climb compared to total expenses because by far the largest component of expenses is the

mortgage payment, which is constant. In a good project the gradually improving profit/loss picture is then transformed in the developer's favour as soon as the mortgage payments cease.

Net Present Value

The final stage in the analysis is to compare the accumulated return on the hydro investment to the alternative of equivalent investments at market rates. This calculation is also a simple spreadsheet operation like the previous one, on which it is based. The previous assumptions on electricity price increases and inflation are retained and another is added: the expected market interest rate on alternative investments. Based on this rate, Table 2 is used to derive a "discount factor", which indicates the present value of a future amount.

TABLE 2

DISCOUNT FACTORS FOR PRESENT VALUE

YEAR	8%	10%	12%	14%	16%	18%	20%
1	0.9259	0.9091	0.8929	0.8772	0.8621	0.8475	0.8333
2	0.8573	0.8264	0.7972	0.7695	0.7432	0.7182	0.6944
3	0.7938	0.7513	0.7118	0.6750	0.6407	0.6086	0.5787
4	0.7350	0.6830	0.6355	0.5921	0.5523	0.5158	0.4823
5	0.6806	0.6209	0.5674	0.5194	0.4761	0.4371	0.4019
6	0.6302	0.5645	0.5066	0.4556	0.4104	0.3704	0.3349
7	0.5835	0.5132	0.4523	0.3996	0.3538	0.3139	0.2791
8	0.5403	0.4665	0.4039	0.3506	0.3050	0.2660	0.2326
9	0.5002	0.4241	0.3606	0.3075	0.2630	0.2255	0.1938
10	0.4632	0.3855	0.3220	0.2697	0.2267	0.1911	0.1615
11	0.4289	0.3505	0.2875	0.2366	0.1954	0.1619	0.1346
12	0.3971	0.3186	0.2567	0.2076	0.1685	0.1372	0.1122
13	0.3677	0.2897	0.2292	0.1821	0.1452	0.1163	0.0935
14	0.3405	0.2633	0.2046	0.1597	0.1252	0.0985	0.0779
15	0.3152	0.2394	0.1827	0.1401	0.1079	0.0835	0.0649

The net present value calculation can be done separately or at the same time as the cash flow calculation. It uses two of the previous six columns (A total revenue, and D total expenses) and adds three new columns:

G: Discount factor (from Table 2, changes each year)
H: Net present value revenues (A times G)
I: Net present value expenses (D times G)

The calculation is done a year (row) at a time. At the end of the table columns G and H are summed to give total net present value of revenues and expenses. (See examples in Appendix D.) These two amounts can be compared. If the net present value of revenues exceeds the net present value of expenses, the project is economically feasible.

The assumptions involved in these analyses should be kept consistent with each other. For example, the expected market interest rate available to the developer might be one or two percentage points below the expected mortgage interest rate. The relation of both these interest rates and the rate of electricity price increases to the assumed inflation rate should also be carefully considered. In fact, the developer undertaking this analysis should perform it many times, varying the assumptions as well as the estimates to discover those variables that have a strong influence on overall feasibility.

Technical and economic feasibility have to go hand in hand.

4

EVALUATING A DOMESTIC SYSTEM

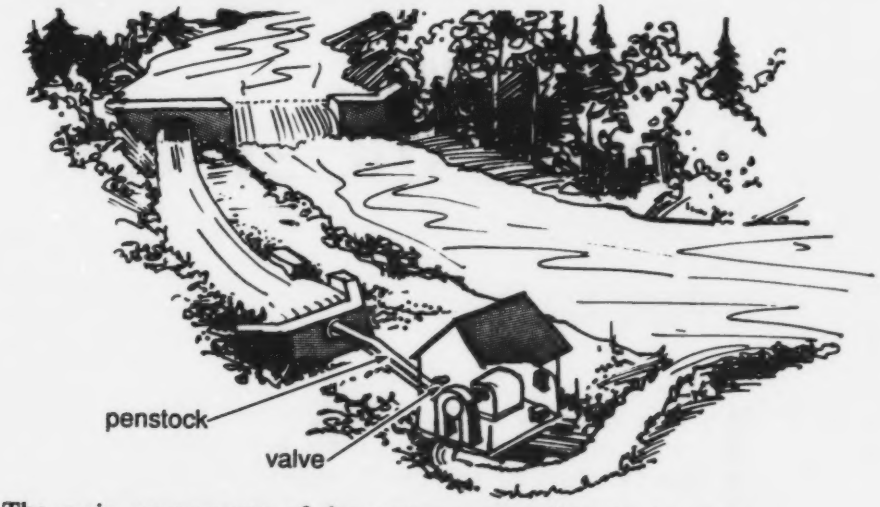
INTRODUCTION

In some cases the installation being considered is the smallest size of micro hydro plant suitable for a home or farm. Its capacity might be 3 to 10kW, enough to provide domestic energy independence or to displace substantial portions of utility power. The general considerations involved in determining the equipment and layout for a larger, commercial-scale system apply even for the smallest micro hydro plant. However, the development of a domestic system is likely to proceed to a greater extent on a simpler, do-it-yourself basis. Different emphasis will appear in the designs considered and the evaluation of them.

A 1kW system can be installed at a good site for a few thousand dollars while a 10kW system, also at a good site, could easily be $25,000 or more. The information below will help in the decisions of what type of system is most suitable and how big a system is needed.

The main components of a micro hydro system in or near the power house are: the turbine which converts the power in the falling water to power in a rotating shaft; the generator which converts the mechanical rotating power to electrical power; the control panel which provides protection for the system and

ensures high quality power; and the transformer which increases or decreases the voltage of the power to a level suitable for direct use (low voltage) or for distribution over some distance (higher voltage). A micro hydro system generating DC power would have a bank of batteries for energy storage and often an inverter to change the DC power to AC before use.



The main components of the system responsible for bringing water to the turbine are: the dam which creates a head of water and allows for submergence of the intake; the penstock which carries the water from the dam to the turbine; and the valve which allows control over the flow of water.

Information beyond that contained in this handbook and other publications can be obtained from a range of sources. In Canada, the Ministry of Natural Resources and your local conservation authority can provide information on stream flow and the approval process as it applies to a particular site. The provincial Ministry of Energy can provide information on economics, financing and is generally prepared to assist the developer to a successful conclusion. The utility will provide information on purchase rates, protection of the equipment and requirements for interconnection.

Information on locating a suitable site is contained in Chapter 2. Once you have a good idea of the potential of the site a

manufacturer should be contacted. The manufacturer can suggest suitable equipment, give prices and can, if desired, provide for a complete installation.

Consulting engineers are also a valuable source of information, particularly for larger sites. A consulting engineer can do a feasibility study, choose equipment and a contractor, and oversee the complete installation of a micro or small hydro system. Chapter 5 should be consulted for government approvals procedures.

DESIGN AND EQUIPMENT

The main considerations are generating system options, estimating power and energy requirements, and estimating the size of system needed. These topics are discussed below.

Generating System

A commercial-scale system will use AC generation of either the dependent "induction" or independent "synchronous" type. (See Chapter 3.1 for a detailed discussion of these types.) Both of these options can also be used at a domestic scale. In addition, however, the feasibility of DC generation should be considered, especially if complete energy independence is a goal.

A DC generating system can confer two advantages. First, generator speed does not have to be controlled to produce suitable current. Therefore, more expensive turbine designs and speed control equipment may be avoided. Moreover, with a DC generator, some power can be drawn even at times when the flow is low. Secondly, unlike AC, DC can be stored in batteries. Such storage can supply extra power for use at peak consumption periods, allowing the turbine and generator to be smaller in size. In some cases these advantages can be decisive for feasibility, particularly if the hydraulic potential of the site itself is small.

On the other hand, the disadvantages of a DC generating system cannot be ignored. First, most domestic appliances require 60

cycle AC. An "inverter" is needed to make the conversion, conversion that will both add to equipment costs and consume some of the available power. Secondly, battery storage capacity is costly and rapidly becomes prohibitive as system size increases. Finally, the distance from the site to the point of consumption becomes critical. Even a 30m run requires a very heavy cable if using DC. The costs of dealing with these disadvantages must be weighed against the advantages of a DC generating system.

In particular, a rather distant site introduces further complications. Unlike AC, DC cannot be raised in voltage by a transformer to reduce power loss over longer transmission distances. To avoid conversion to AC for transmission and back again to DC for storage, the installation of battery storage at the site might be considered. However, since storage batteries lose their efficiency at cold temperatures, they require a heated location, which may not be feasible at the hydraulic site. Obviously with an independent DC system it is especially advantageous to have the water power site nearby.

Power and Energy Requirements

The developer seeking energy independence should estimate as carefully as possible the domestic requirements for power and energy that the system must fulfill. An overestimated system will be too costly, an underestimated system inadequate.

Preliminary estimates can be made with the help of Table 3. The **peak power consumption** is the maximum amount of electricity that will be needed at any one moment. To estimate this amount, add together the figures from the "Power" column for all appliances that could conceivably be on simultaneously. A typical peak consumption would be 7kW. The **average energy consumption** is the average number of kilowatt hours used over a given period. Monthly estimates can be made by dividing the monthly average energy consumption by the number of hours in that month (number of days times 24).

These preliminary estimates should be checked. For peak power requirements it is advisable to create a list of the actual wattage of all electrical appliances and equipment to be served. Appliances will show maximum wattages on their nameplates; for electric

TABLE 3

TYPICAL HOUSEHOLD APPLIANCE LOADS

APPLIANCE	POWER (WATTS)	AVERAGE HOURS USE PER MONTH	ENERGY USED (kWh) PER MONTH
Air Conditioner	1560	74	116
Blender	600	3	2
Car Block Heater	450	300	135
Clock	2	720	1
Clothes Dryer	4600	19	87
Coffee Maker	800	12	10
Electric Blanket	200	80	16
Electric Heating	6000	250	1500
Exhaust Fan (Kitchen)	250	30	8
Freezer (chest 15 cft)	350	240	84
Hair Dryer (hand-held)	1200	5	6
Hot Plate (1 burner)	500	14	7
Iron	1100	12	13
Light - each 60 watt	60	120	7
- each 100 watt	100	90	9
- each 4 ft fluorescent	50	240	12
Mixer	125	6	1
Port. Electric Heater	1250	350	440
Radio (transistor)	10	120	1
Range (4 burner only)	6000	10	60
Range & Oven	7200	10	72
Refrigerator (manual 14 cft)	300	200	60
14 cft frost free	360	500	180
Sewing Machine	100	10	1
Stereo (transistor)	30	120	4
Shop Tools:			
1/4 in drill (1/16 hp)	250	4	1
Skill saw (1 hp)	1000	6	6
Table saw (1 hp)	1000	4	4
Lathe (1/2 hp)	460	2	1
Toaster	1150	4	5
TV - black & white	250	120	30
- colour	350	125	44
Washing Machine (15 loads)	700	12	8
Water Heater - 30 gallon	1200	89	107
- 40 gallon	2000	89	179
- 50 gallon	3000	89	286
Water Pump (1/2 hp)	460	44	20
Vacuum Cleaner	750	10	8

motors it is useful to recall that one horsepower is 750 watts. The result may be a revised peak power requirement. Where the power differs from that in Table 3, the "Energy Used" number should also be adjusted accordingly. These changes may lead to a revised average energy consumption estimate as well, which can then be further checked against previous electrical utility billings if they are available. Again, seasonal variations must be reflected in the estimates, so that at least one complete year's utility bills should be consulted. Revisions to the monthly average energy consumption estimates will result in changes to the average monthly power demand estimates as well.

Uncertainties in these estimates are inevitable, of course. One way to compensate for uncertainties in energy consumption is to change the assumptions for the number of hours a month certain appliances are used. By producing a variety of estimates based on different assumptions and seeing how widely they range, it will be possible to develop a set of figures that can be used with some confidence in determining the size of system required.

In an independent, domestic-scale micro hydro system, the size and cost of the system are associated with the power and energy required. Conservation measures can save costs directly. The most vital concern is usually the peak power consumption, which reflects the way in which the electricity is used. Identifying these peaks -- when they occur and what equipment is involved -- is an important step towards cutting system costs. In analysing requirements, various ways of adjusting consumption patterns to limit the size and duration of peaks should be thoroughly explored. Incorporate these potential effects in the varying assumptions mentioned above.

Energy consumption is as much a matter of lifestyle as technology

System Size

An independent system must be large enough to meet the peak power consumption. There are two ways of doing this. One way is to size the generating system to meet the consumption peak and design it to "dump" excess power at off-peak times, possibly to a water or space heater. Automatic load control switching is an applicable option in such a design. With an automatic load control design, the switching of power to the additional loads is automatically determined. As demand approaches the system's capacity, the non-essential loads are cut off automatically in a pre-determined order. This approach is often the most cost-effective.

The other way to meet consumption peaks is to size the generator to meet or slightly exceed the average power consumption and use battery storage to accommodate the peaks. If the site is so small that its power output cannot meet the consumption peaks, there may be no alternative to using storage batteries. But at sites where the choice of approaches exists, it will obviously be an important decision for the developer to make.

Whether or not a site offers this choice can be found with the help of the nomograph (Figure 1) and the Flow Duration Curve (Figure 2). From the head available and the power required, the nomograph gives the flow required. This flow is then sought on the flow duration curve. If the flow for the peak power requirement (plus a 10 per cent increment to cover uncertainties) is available for at least 95 per cent of the year, the choice is available. If the flow for the average power requirement (plus 10 per cent) is not available at least 95 per cent of the year, energy independence is not feasible at all, though some power displacement will be. If the 95 per cent flow lies somewhere between the average and the peak power requirement flows, energy independence is possible with the use of battery storage. Since many uncertainties are involved, such as the efficiency of the turbine and generator (the nomograph assumes 70 per cent), a decision should not be made quickly if the tolerances are close.

More precise and detailed information about the site and from turbine and equipment manufacturers will be used to refine the

preliminary estimates. If a choice is available between battery storage and a larger generator with an energy dump, the requirements, costs, safety, and convenience of both approaches can be estimated and compared to form the basis of a decision.

ECONOMIC ANALYSIS

An economic analysis of the feasibility of a domestic-scale micro hydro system can be conducted in exactly the same way as that of a commercial-scale system, described in Chapter 3. In both cases, preliminary estimates can be revised and refined as more precise data are gathered. Annual costs and revenues are estimated in a similar manner, except that with an independent system there will be no sales revenues to supplement displacement revenues. The cost-benefit analysis based on assessments of cash flow and net worth are equally important and as easily done. With this approach, a picture of the long-term feasibility of a potential project can be developed at the earliest stages, and if the results are positive they can be refined and reviewed at each subsequent decision point.

5

THE APPROVALS PROCESS

When the feasibility analysis of the project is still in its early stages, the developer should make contact with a number of government offices able to provide advice and assistance. This chapter is devoted to the various government bodies involved in micro and small hydro plants. The federal government procedures listed below are relevant across Canada. The provincial bodies cited are Ontario departments; where appropriate, readers should contact their provincial counterparts. Assistance in reaching the appropriate representatives is available from the Ontario Ministry of Energy by writing to the ministry at 56 Wellesley St. West, Toronto, Ontario, M7A 2B7.

The first step in the process is the submission of a summary statement of the expected environmental impacts of the proposed project. This statement will be examined by representatives of the provincial Ministries of Natural Resources and the Environment, the local municipality, and the local conservation authority. This submission, like most of those required for the project, should be coordinated through the local district office of the Ministry of Natural Resources (see Ontario addresses in Appendix F).

The Ministry of Natural Resources can indicate the requirements to be satisfied and provide guidance on how to conduct the

assessment or to proceed with the submission. Depending on the nature and scale of the project, the assessment submitted may be as brief as two or three pages. For larger installations, or one requiring the construction of a new dam, a significantly more detailed analysis is required. The assessment may result in a requirement that the project include certain mitigating measures to reduce adverse environmental impacts. For example, if interference with fish passage will occur, the developer may be required to incorporate a fish ladder or fishway into the design.

The acceptance of this assessment enables the developer to proceed with other approvals that are necessary -- Figure 3 identifies them. Below are descriptions of the statutory requirements for each approval. Though the figure presents a sequential approach, the approvals can, in some cases, be undertaken concurrently.

THE FEDERAL ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS

Under the federal Environmental Assessment and Review Process (EARP), an environmental impact assessment is required if the project receives federal funding, or involves federal land, and is considered by the approving agency or agencies to have potentially significant environmental impacts.

The EARP Process consists of two phases: the screening phase and the formal review phase.

In the initial screening phase, the federal department or agency responsible for the project is required to review the proposal for unwanted environmental impacts. If none are identified, the developer may then proceed with the project provided that the other requirements of the approval process are satisfied. If it is determined that the project could have an adverse impact on the environment, the proposal would be sent to the federal Environmental Assessment and Review Office for formal review.

If the nature and scope of the impacts are unclear, the agency may request that the developer undertake an Initial Environmental

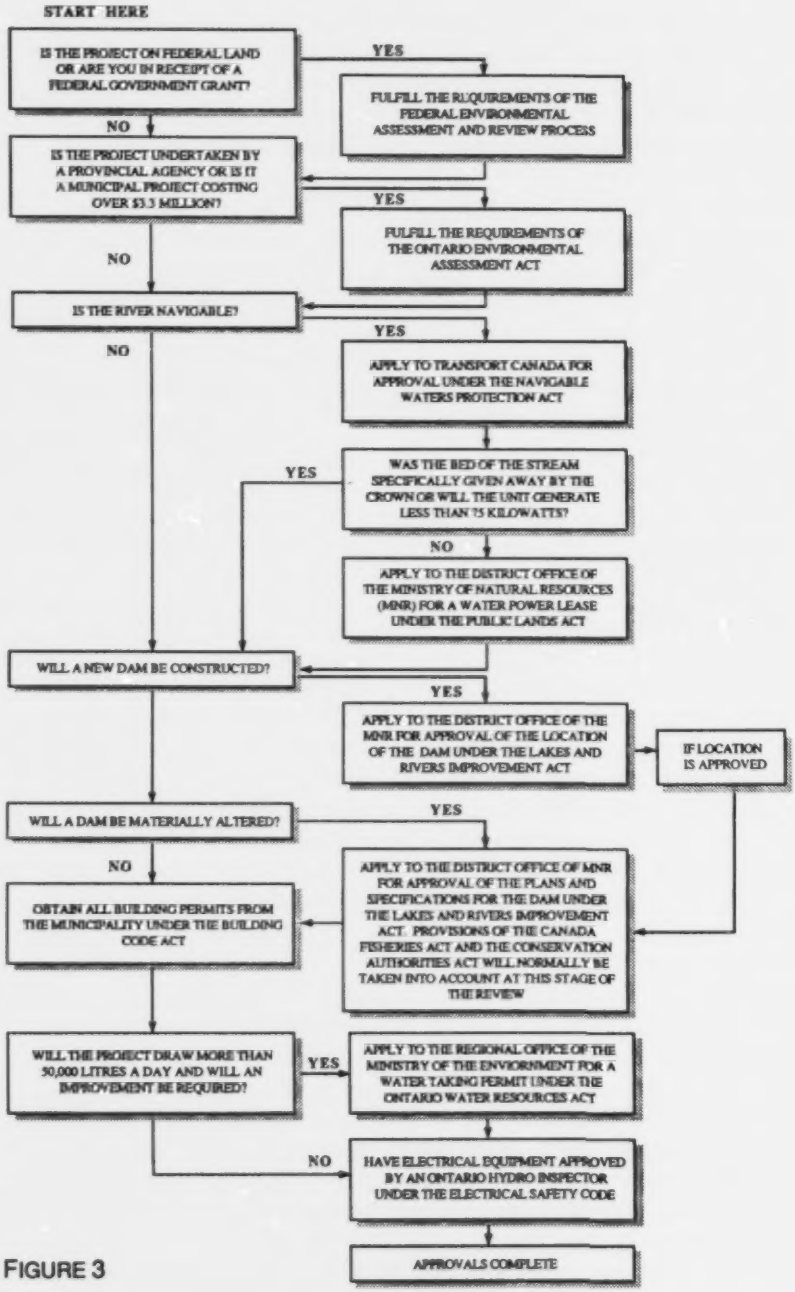

START HERE
IS THE PROJECT ON FEDERAL LAND OR ARE YOU IN RECEIPT OF A FEDERAL GOVERNMENT GRANT?
YES
FULFILL THE RUQUIREMENTS OF THE FEDERAL ENVIRONMENTAL ASSESSMENT AND REVIEW PROCESS
NO
IS THE PROJECT UNDERTAKEN BY A PROVINCIAL AGENCY OR IS IT A MUNICIPAL PROJECT COSTING OVER $3.3 MILLION?
YES
FULFILL THE REQUIREMENTS OF THE ONTARIO ENVIRONMENTAL ASSESSMENT ACT
NO
IS THE RIVER NAVIGABLE?
YES
NO
APPLY TO TRANSPORT CANADA FOR APPROVAL UNDER THE NAVIGABLE WATERS PROTECTION ACT
WAS THE BED OF THE STREAM SPECIFICALLY GIVEN AWAY BY THE CROWN OR WILL THE UNIT GENERATE LESS THAN 75 KILOWATTS?
YES
NO
APPLY TO THE DISTRICT OFFICE OF THE MINISTRY OF NATURAL RESOURCES (MNR) FOR A WATER POWER LEASE UNDER THE PUBLIC LANDS ACT
WILL A NEW DAM BE CONSTRUCTED?
YES
APPLY TO THE DISTRICT OFFICE OF THE MNR FOR APPROVAL OF THE LOCATION OF THE DAM UNDER THE LAKES AND RIVERS IMPROVEMENT ACT
IF LOCATION IS APPROVED
WILL A DAM BE MATERIALLY ALTERED?
YES
NO
APPLY TO THE DISTRICT OFFICE OF MNR FOR APPROVAL OF THE PLANS AND SPECIFICATIONS FOR THE DAM UNDER THE LAKES AND RIVERS IMPROVEMENT ACT. PROVISIONS OF THE CANADA FISHERIES ACT AND THE CONSERVATION AUTHORITIES ACT WILL NORMALLY BE TAKEN INTO ACCOUNT AT THIS STAGE OF THE REVIEW
OBTAIN ALL BUILDING PERMITS FROM THE MUNICIPALITY UNDER THE BUILDING CODE ACT
WILL THE PROJECT DRAW MORE THAN 50,000 LITRES A DAY AND WILL AN IMPROVEMENT BE REQUIRED?
YES
APPLY TO THE REGIONAL OFFICE OF THE MINISTRY OF THE ENVIORNMENT FOR A WATER TAKING PERMIT UNDER THE ONTARIO WATER RESOURCES ACT
NO
HAVE ELECTRICAL EQUIPMENT APPROVED BY AN ONTARIO HYDRO INSPECTOR UNDER THE ELECTRICAL SAFETY CODE
APPROVALS COMPLETE

FIGURE 3

Evaluation (IEE). The IEE normally includes a description of the project and an evaluation of the possible alternatives to the undertaking. Once again, the initiating department must decide if the project impacts warrant a more thorough evaluation. Such a decision would bring the project under formal review.

Should the project go to formal review, the developer would be responsible for the preparation of a more detailed environmental assessment of the project. The assessment is first submitted to the initiating department for acceptance. Upon acceptance, an independent panel is established to review and evaluate the material submitted for consideration, including the developer's assessment, technical reviews of the assessment by various government agencies, and public submissions on the project.

The panel makes its recommendations to the federal Minister of the Environment for approval. The final decision for approval lies with the Minister and the federal Cabinet.

THE ONTARIO ENVIRONMENTAL ASSESSMENT ACT

The Environmental Assessment Act requires that all projects undertaken by provincial agencies and certain projects undertaken by municipalities be the subject of an environmental assessment. Any individual project may, upon application, be specifically exempted by the Minister of the Environment from the provisions of the Act. **All private projects are exempt from the Act,** unless explicitly so ordered by the Minister of the Environment. Small hydro projects undertaken by municipalities are exempt unless the total cost of the project is more than $3.3 million (in 1985).

If an environmental assessment is required, the developer must show that the environmental impacts of the various alternative courses of action to the project have been considered by the developer and evaluated before the chosen course of action had been selected. The assessment document must include a description of the purpose and rationale of the project as well as a description and evaluation of the probable impacts of each of the alternatives. It should also include an evaluation of any social, cultural, and economic impacts that may be involved in the

undertaking and the possible mitigation measures that could be implemented in the project to correct for unwanted impacts.

The formal document must be submitted to the Ministry of the Environment for approval. When the assessment is submitted to the ministry, a technical review of the document is prepared, and both the assessment and review are made available for public inspection and comment for at least thirty days. During this period any person may request that the document be submitted to the Environmental Assessment Board for public hearing.

The ministry has the authority to amend the assessment and request that the developer carry out additional research related to the proposed development. If the assessment document is accepted by the ministry and a hearing of the Environmental Assessment Board is not required, a decision to approve or reject the project will be made by the Minister. A decision of the Environmental Assessment Board may be altered by the Minister within twenty-eight days of its release or a new hearing of the board ordered.

THE NAVIGABLE WATERS PROTECTION ACT

It must be determined whether the water course proposed for development is navigable. In general, a stream is considered to be navigable if, at average flow, it is suitable for commercial and recreational boating. In most cases the district office of the Ministry of Natural Resources will be able to advise whether a particular stream is navigable, although the decision will be an administrative one and can still be challenged in a court of competent jurisdiction. Approval under the Navigable Waters Protection Act may be required even if a dam exists.

If the stream is navigable, the developer must apply to Transport Canada for approval of construction, ensuring that the project will not interfere with local navigation. An application for approval under Section 5 of the Navigable Waters Protection Act can be obtained from Transport Canada. It must be submitted to the Chief, Navigable Waters Protection Act, Programs Division, Canadian Coast Guard, Transport Canada, 6th Floor, Tower A, Place de Ville, Ottawa, Ontario, K1A 0N7.

THE BEDS OF NAVIGABLE WATERS ACT

Under the Beds of Navigable Waters Act (RSO 1970 Chapter 41) the beds of all navigable waters belong to the Crown unless expressly granted to an individual in the original letters patent. If the stream is considered to be unnavigable, the bed belongs to the owner or owners of the property adjacent to the stream.

If the stream bed is owned by the Crown, the developer must apply to the district office of the Ministry of Natural Resources for a Water Power Lease under the Public Lands Act (RSO 1970 Chapter 380).

THE LAKES AND RIVERS IMPROVEMENT ACT AND THE CANADIAN FISHERIES ACT

If the project requires either the construction of a new dam or material alteration of an existing one -- regardless of whether the landowner owns the stream bed or if the stream is navigable -- the project must be approved by the Ontario Ministry of Natural Resources, under the Lakes and Rivers Improvement Act (RSO 1970 Chapter 233).

If a new dam is required, the owner must first apply, under Section 10, to a district office of the Ministry of Natural Resources for approval of the location of the dam. Approval must also be sought for the developer's detailed plans and specifications for the new dam (Section 10), or for modifications to an existing dam (Section 12).

The Ministry of Natural Resources may require that a fishway be installed around the new or existing dam. If the Minister intends to refuse approval of the dam, the applicant must be given 15 days notice of this intention and the reason for refusal (Section 8a). At the applicant's request, the Minister will convene a public inquiry regarding the proposed undertaking.

The Minister will then consider the report of the inquiry and decide whether to approve the application (Section 8b). The Minister's

decision may be appealed to the Lieutenant Governor-in-Council (the Cabinet) (Section 8c).

New dams, modifications to existing dams and the intake of the turbine are also subject to the Canadian Fisheries Act (RSO 1970 Chapter F-14).

A project may be prohibited if it will result in harmful alteration, disruption, or destruction of fish habitat unless special permission is granted by the Minister of Natural Resources (Section 31). If the project is approved, the Minister may still require that a fishway be installed around any dam or other obstruction and may also reqire that a minimum flow of water be maintained over the dam (Section 20). The Minister may also require a fish guard to be installed on the turbine's water intake or similar measures designed to prevent fish from passing through the turbine (Section 28).

In Ontario, the Canada Fisheries Act is administered by the Ministry of Natural Resources. The requirements of the Act are considered in conjunction with the review under the Lakes and Rivers Improvement Act.

CONSERVATION AUTHORITY APPROVAL

If the proposed site lies within the boundaries of a conservation authority, the authority will assess the project's impacts. Its review normally proceeds concurrently with the Ministry of Natural Resources under the Lakes and Rivers Improvement Act. Documents submitted to a district ministry office will be forwarded to the conservation authority involved at the developer's request. However, separate approval may be required, so the applicant should approach the authority early in the approval process. A conservation authority's main concern is usually the effect the project would have on flood protection.

THE ONTARIO WATER RESOURCES ACT

Ministry of the Environment approval is also required if the project impounds water and if flow at the site exceeds 50,000 litres per

day -- as it will at even the smallest micro hydro site. A water taking permit, under section 37 of the Ontario Water Resources Act (RSO 1970 Chapter 352) may be obtained by applying to the Chief, Water Resources Assessment, at a regional office of the Ministry of the Environment. The district office of the Ministry of Natural Resources will be able to direct you to the proper Ministry of the Environment regional office.

THE POWER CORPORATION ACT– ELECTRICAL SAFETY CODE

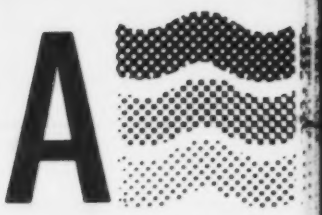
Installation of the generator, and other related electrical equipment, is subject to the Electrical Safety Code, a set of regulations administered by Ontario Hydro under the Power Corporation Act (RSO 1970 Chapter 354). As with most electrical installations, the electrical components of a hydraulic generating station must be approved by an electrical inspector before use. Utilities are exempt from these inspections.

BUILDING PERMITS

A municipality may require permit applications for parts of the project. Discuss your plans with the proper officials early in the approvals process to determine these requirements.

SUMMARY

The approval process is important. We all want to protect the environment and to make best use of our natural resources. The approval process is not the government against the developer. It is a search for an acceptable approach that gives the optimum use of a stretch of stream. Your plans may change for the better as a result of useful advice offered during the approval process.



MEASURING FLOW AND HEAD AT THE SITE

MEASURING FLOW

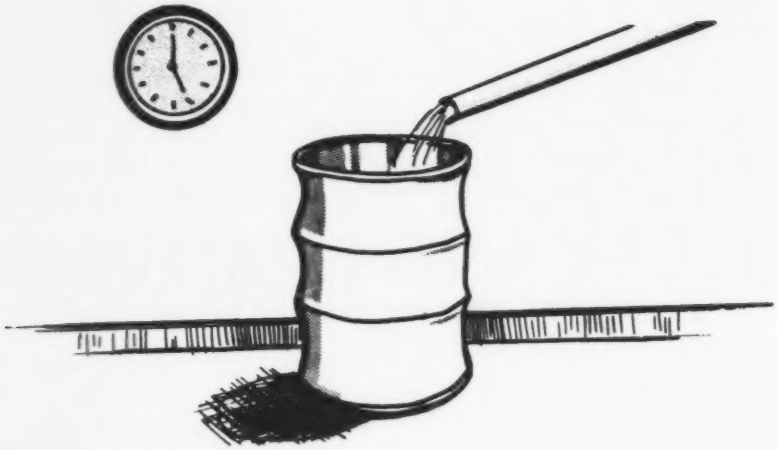
Container Method

The container method of measuring stream flow is practical only in cases where the total flow of the source is small. Water from the source is collected and measured according to the size of the container and the time required to fill it. The container used must be of sufficient capacity to accommodate the total flow for at least thirty seconds. The container method is therefore practical only for small springs and streams and for existing dam sites where water is released through a discharge pipe.

With the values known for these two variables -- the size of the container and the time required to fill it -- the rate of flow can be determined using the following equation:

$$Q = V/t,$$

Where Q is the rate of flow in litres per second, V is the volume of water in litres, and t is the time of measurement in seconds.



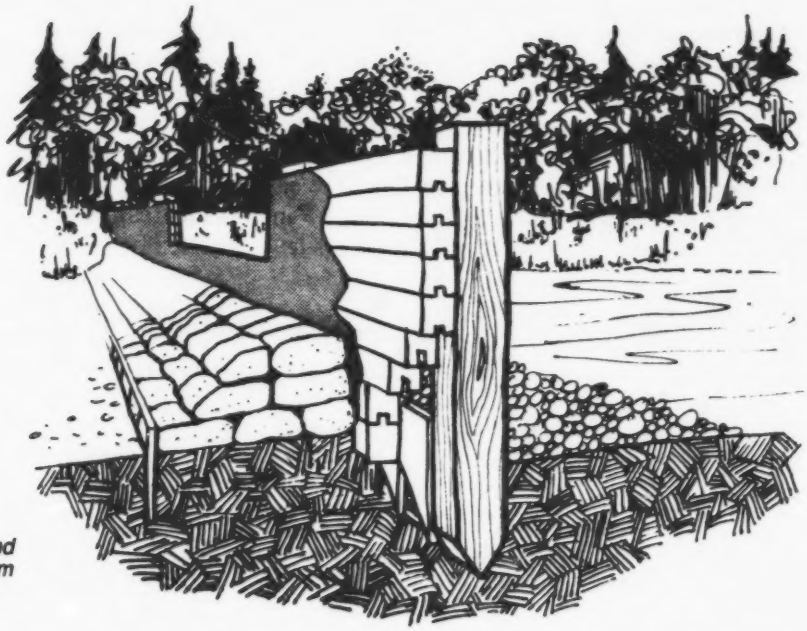
Container method for measuring flow

Weir Method

Where the flow is too large for the container method, the weir method can provide accurate measurements of flow. A temporary dam must be constructed unless an existing dam has water continuously passing over the spillway.

There are two types of temporary dams which may be used to construct a weir. The type best suited for a particular site would depend on the size of the stream and the height of the dam required. The "tongue and groove" dam and weir (Figure A.1) is constructed from lumber spiked together. This type of dam is practical only in the case of relatively small streams. The "log crib" dam, which is also formed from lumber spiked together but in "corn crib" fashion, is a more appropriate design for larger streams and rivers.

Before the construction of a temporary dam can begin, the size of the weir must be calculated. To do this, the deepest point of the stream where the dam is to be constucted must be found. The depth of the weir opening must be at least equal to the depth of the stream at this point, and the width at least three times the depth of the opening. The downstream side of the weir must be bevelled at no less than 45 degrees, and the bottom must be level with the stream bed.



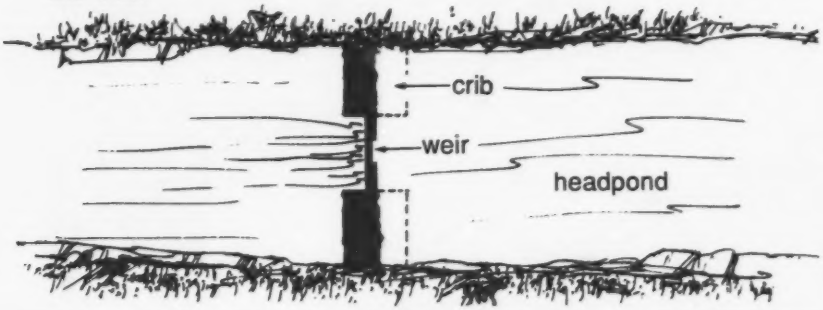
tongue and groove dam

In constructing a tongue and groove dam, a trench must be first dug across the entire width of the stream perpendicular to the flow so that the bottom piece of lumber can be placed level. Clay and earth can be used to make the trench level. Next, the downstream priming planks, which are wooden boards of tongue and groove design, should be driven approximately .75 metres into the stream bed to limit the amount of seepage that would occur under the dam. The timber anchor post can then be driven into the stream bed as far as possible and the notch made.

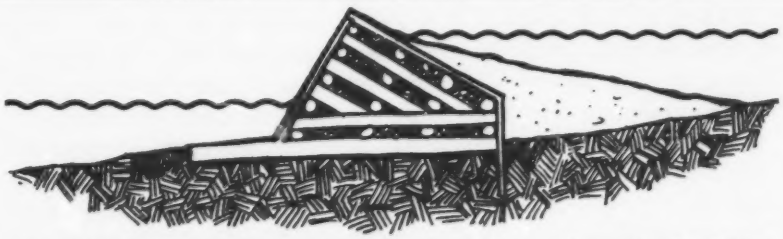
Once the upstream priming planks are in place and the upstream face of the dam made waterproof using plastic sheeting or sealant, sand bags or earth fill should be placed in front of the dam to provide additional structural integrity.

Lastly, a post should be driven into the stream bed approximately 1.5 metres upstream from the dam and the top of the post made level with the bottom of the weir. The post should be located within reach of the river bank to facilitate easy reading of the water levels.

To build a crib dam, logs should be arranged in "corn crib" (cross) fashion approximately .5 metres apart and spiked together. The spaces between the logs should be filled with rocks and gravel and the upstream sides and bottom of the dam covered with earth and clay to seal the edges. The priming planks should then be installed on the upstream side of the dam at least .75 metres into the stream bed and the weir. The last step, as in the case of the tongue and groove design, is to drive a post about 1.5 metres upstream from the dam ensuring that the top of the post is level with the bottom of the weir.



Overhead view of crib dam with weir



Cross section of the crib dam

To calculate flow, the depth of the water above the weir should be measured to the nearest 1/2 centimetre (cm).

Table A.1 is a weir table. It lists water flow per centimetre of stream depth over the weir. To calculate total flow, locate the value for the recorded depth of the water above the weir opening and multiply this by the width of the opening.

For example:

If the weir is 120 cm wide and the depth of the flow above the bottom of the weir is 35cm, using the value from Table A.1, total flow is (120 x 0.0616) 7.39 m^3/minute. To express this in litres per second, multiply by 60 to convert to seconds, and then by 1,000 (1 cubic metre = 1,000 litres).

TABLE A.1

WEIR TABLE

FLOW DEPTH (cm)	m^3/min/cm of WEIR WIDTH	FLOW DEPTH (cm)	m^3/min/cm of WEIR WIDTH	FLOW DEPTH (cm)	m^3/min/cm of WEIR WIDTH
0.5	0.0009	15.5	0.0272	30.5	0.0537
1.0	0.0018	16.0	0.0281	31.0	0.0546
1.5	0.0026	16.5	0.0290	31.5	0.0554
2.0	0.0035	17.0	0.0299	32.0	0.0563
2.5	0.0044	17.5	0.0307	32.5	0.0572
3.0	0.0053	18.0	0.0316	33.0	0.0581
3.5	0.0061	18.5	0.0325	33.5	0.0590
4.0	0.0070	19.0	0.0334	34.0	0.0598
4.5	0.0079	19.5	0.0342	34.5	0.0607
5.0	0.0088	20.0	0.0352	35.0	0.0616
5.5	0.0097	20.5	0.0361	35.5	0.0625
6.0	0.0106	21.0	0.0370	36.0	0.0634
6.5	0.0114	21.5	0.0378	36.5	0.0642
7.0	0.0123	22.0	0.0387	37.0	0.0651
7.5	0.0132	22.5	0.0396	37.5	0.0660
8.0	0.0140	23.0	0.0405	38.0	0.0669
8.5	0.0149	23.5	0.0414	38.5	0.0678
9.0	0.0158	24.0	0.0422	39.0	0.0686
9.5	0.0167	24.5	0.0431	39.5	0.0695
10.0	0.0176	25.0	0.0440	40.0	0.0704
10.5	0.0184	25.5	0.0449	40.5	0.0713
11.0	0.0193	26.0	0.0458	41.0	0.0722
11.5	0.0202	26.5	0.0466	41.5	0.0730
12.0	0.0211	27.0	0.0475	42.0	0.0739
12.5	0.0220	27.5	0.0484	42.5	0.0748
13.0	0.0228	28.0	0.0493	43.0	0.0757
13.5	0.0237	28.5	0.0502	43.5	0.0766
14.0	0.0246	29.0	0.0510	44.0	0.0774
14.5	0.0255	29.5	0.0519	44.5	0.0783
15.0	0.0263	30.0	0.0528	45.0	0.0792

Float Method

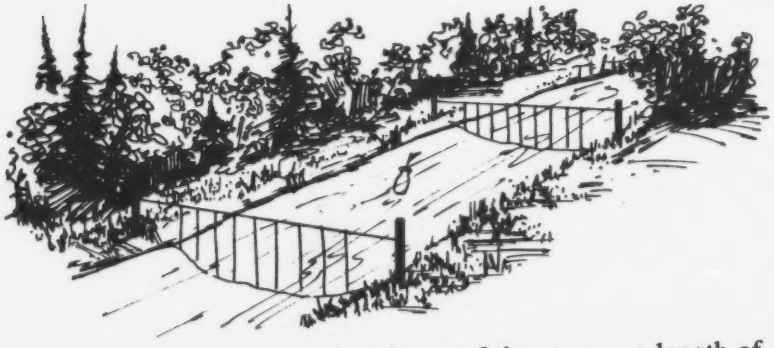
In the case of larger streams and small rivers where the construction of a weir may not be practical, the float method can be used to estimate flow.

The flow is equal to the area of the cross section of water multiplied by the velocity of the water or, in other words, the speed at which the cross sectional area of water is moving.

Flow may be calculated using the following equation:

$$Q = A \times V,$$

where Q is the flow in cubic metres per second, A is the cross-sectional area in square metres and V is the velocity of water in metres per second.



To determine the cross-sectional area of the stream, a length of stream of at least 10 metres should be used. The length chosen should be fairly straight, the sides more or less parallel, and the stream bottom relatively flat.

Stakes should be driven on both sides at each end of the chosen length of the stream. Wires or ropes are then strung between the stakes across the river at both ends and made level. The wires are divided with markers into equal segments of approximately 0.5 metres, as shown in Figure A.2. The depth of the water at the point directly below each marker should be measured and the results added together.

To determine the average cross sectional depth of the stream, the sum of the recorded depths at both crossings is divided by the number of measurements made:

$$Da = \frac{d1 + d2 + d3 \ldots + dn}{n}$$

where Da is the average depth, d1 ... dn are the measured depths at each marker, and n is the number of markers on both wires. To find the cross-sectional area of the stream, multiply the average depth, as determined above, by the average lengths of the two wires.

Next, the velocity of the stream flow must be determined. For a float use an orange, a small piece of wood, or a bottle partially filled with sand. Release the float at the point of the upstream wire and record the time required for the float to reach the second wire. To compensate for any variations in the rate of surface flow, this procedure should be repeated at least six to eight times at different points across the width of the stream and the results averaged.

Since water at the bottom of the stream does not move as quickly as surface water because of the resistance encountered on the stream bed, a correction factor must be applied to the results obtained above. In the case of relatively straight streams free of large rocks and other obstructions, a correction factor of 0.8 should be used. For streams with rough beds or with large obstructions, a correction factor of 0.7 or 0.6 may be required. The average measured surface time is then multiplied by the correction factor to find the corrected average time.

For example, suppose the distance between the wires is 12 metres, the stream bottom is relatively smooth, and the sum of the eight time measurements recorded is 166 seconds. The average time is 166/8 = 20.75 seconds.

Velocity is distance divided by time. The stream velocity is therefore (12/20.75) 0.58 metres/second. For a stream bed that is relatively smooth and free of obstructions the correction factor is 0.8. Therefore the corrected velocity is (0.58 x 0.8) 0.46 metres/seconds.

Now that the values for both the cross-sectional area of the stream and the velocity are known, the rate of flow is determined by multiplying them together. Suppose the cross sectional area is one square metre, then the flow is:

$Q = A \times V$
$= 1.00\ m^2 \times 0.46\ m/sec.$
$= 0.46\ m^3/sec.$ or 460 l/sec.

As in the case of the weir method, it is advisable that measurements be made for at least five different flow days and that four to six measurements be taken and averaged for each flow day. Also, to compensate for any seasonal variations in flow, the entire procedure should be repeated at least once three to four months after the first set of data is collected.

Measuring Head

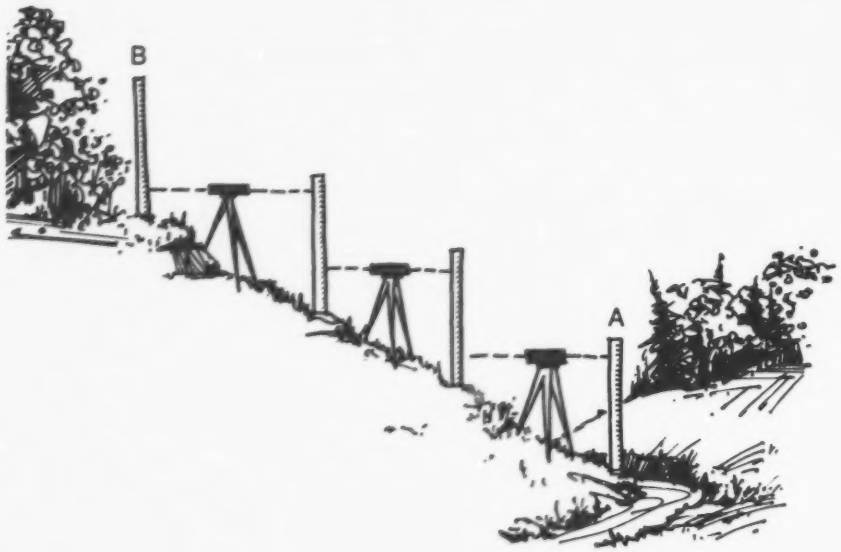
Pool to pool or gross head is the change in elevation or vertical fall or water measured in metres or feet. If a power canal is planned, gross head would be the change in vertical elevation from the water surface at the point of the penstock intake to the tail water outlet.

There are two ways to determine the gross head. The survey method uses standard surveying equipment (or the services of a professional surveyor). The pressure method uses a hose and a pressure gauge.

Survey Method

The proposed location of the powerhouse and penstock intake structure should be used as reference points in measuring head. Place the measuring rod on a steady object at the waterline of the powerhouse location and set up the level in line of sight of the rod at a point between the rod and intake location. When the instrument is properly levelled, record the height of the rod at the line of sight.

The rod should then be moved upstream to a point above the instruments. The height of the rod is again recorded. Subtracting this reading from the first reading gives the vertical distance between A and B as shown in the diagram.



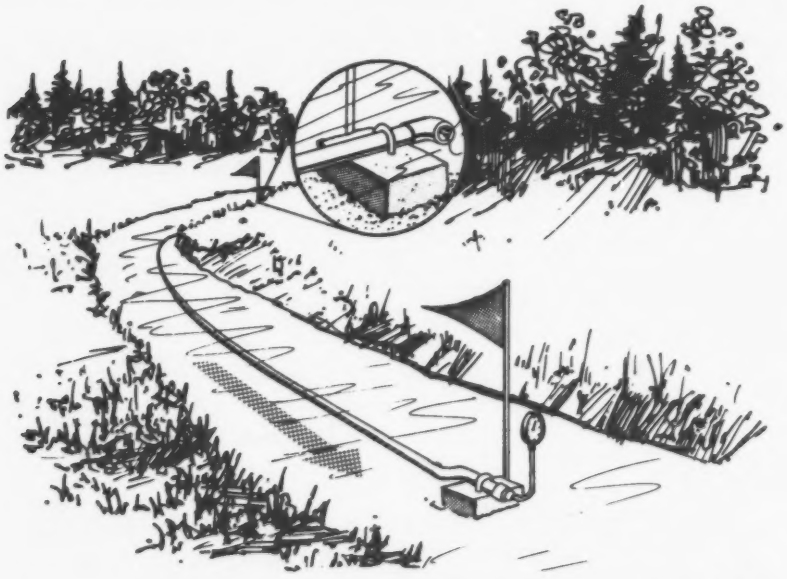
This procedure should be continued, with the instrument assuming the position of the rod at the previous reading, until the point of the penstock intake is reached. The sum of the differences is the gross head of the stream at the site.

Pressure Method

In this technique, head is measured according to the static pressure of water. A column of water one metre high exerts a pressure equal to 9.8 kilopascals (kPa) or 1.42 pounds per square inch (psi).

A pressure gauge -- which can be purchased at a nominal cost -- is connected to the bottom end of a long hose so that the gauge will show the static pressure in the hose. The gauge used should be as accurate as possible since relatively small changes in pressure will be measured.

Start with the lower end of the hose at the proposed site of the powerhouse tailrace. Submerge the hose, removing all air and ensuring that the water in it can flow freely. Anchor the upstream end of the hose and connect the pressure gauge to the lower end of the hose. The intake end of the hose should be at a right angle to the flow so that only static pressure and not water pressure is measured. Record the pressure indicated on the gauge.



If the upstream end of the hose does not reach the point of the proposed intake, mark its location so that the lower end can be placed at this point and the procedure repeated until the surface level of the water at the intake point is reached.

When the reading or readings have been recorded, add all the pressures -- if more than one -- and divide the resulting sum by 9.8, the value for the pressure of one metre of water. For example, suppose six hose lengths are required, producing six measurements that add up to 218.4 kPa. The gross head is therefore (218.4/9.8) = 22.3 metres.

B

DERIVING A FLOW DURATION CURVE

The flow duration curve (example in Figure 2) is a very useful tool for describing the flow of a stream. From this curve decisions can be made on how large a generating unit is practical.

The curve is drawn using available flow data. Data gathered over several years should be used if at all possible. It is also important that approximately equal amounts of data be available for each month.

Do not use monthly averages to plot the flow duration curve. Daily averages may be used if a lot of data is available.

The curve is plotted on ordinary graph paper. The scale on the left side of the graph is flow in litres per second. The scale on the bottom is the percentage of exceedance.

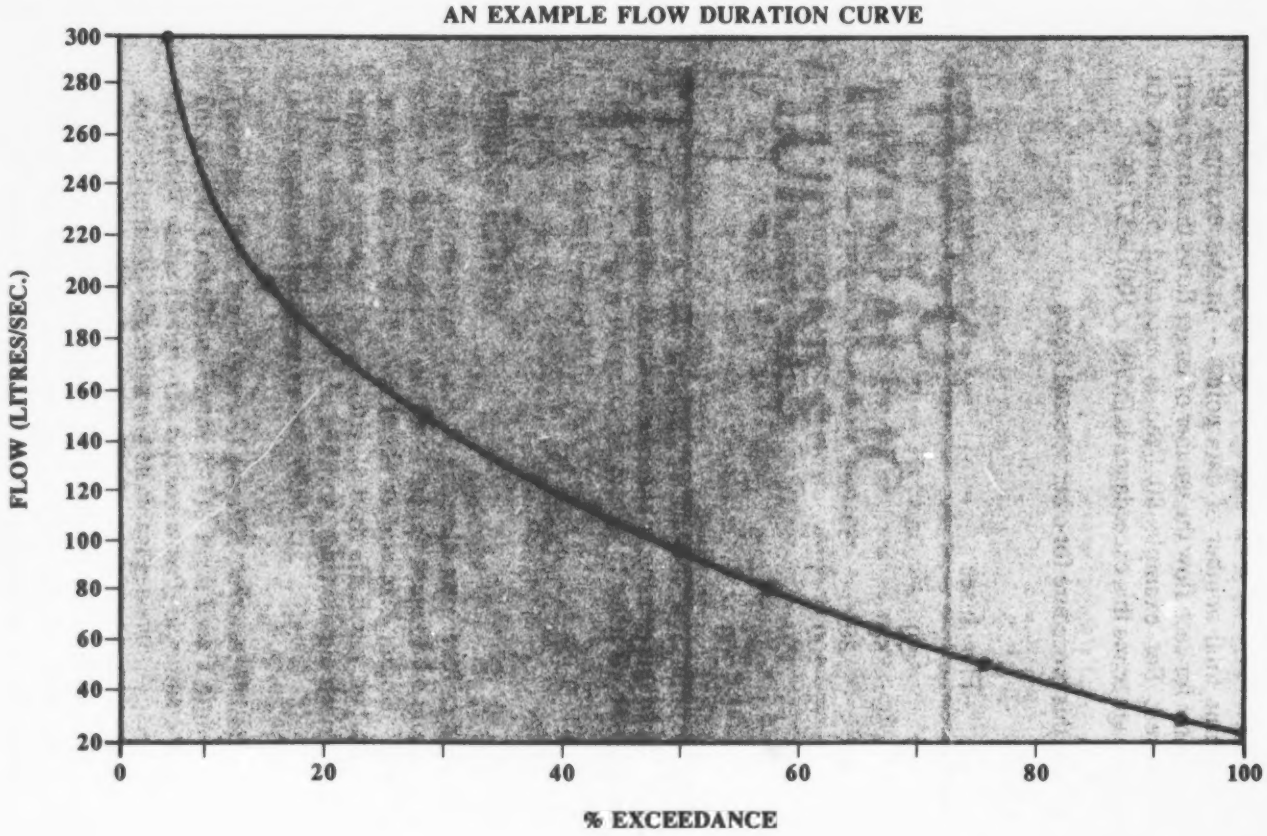
The example curve was plotted using the very small data set presented below. Much more data are required before a curve with any reliability can be plotted for a real stream.

Example flow data:

Flow in L/sec.

		1981	1982	1983	1984
Jan.	01	200	180	160	140
	15	130	100	120	110
Feb.	01	100	120	100	200
	15	250	80	110	190
March	01	300	150	290	300
	15	170	250	320	320
April	01	350	320	310	220
	15	190	290	230	230
May	01	140	60	150	170
	15	60	40	90	120
June	01	170	120	60	110
	15	120	30	130	130
July	01	40	40	70	40
	15	15	60	40	60
Aug.	01	60	70	30	20
	15	80	30	40	40
Sept.	01	20	20	20	30
	15	20	30	20	50
Oct.	01	30	40	30	20
	15	90	60	40	60
Nov.	01	150	90	60	50
	15	170	120	80	90
Dec.	01	220	190	120	90
	15	160	170	150	130

FIGURE 2


AN EXAMPLE FLOW DURATION CURVE
FLOW (LITRES/SEC.)
300
280
260
240
220
200
180
160
140
120
100
80
60
40
20
0
20
40
60
80
100
% EXCEEDANCE

Calculation of % exceedance data:

Determine total number of data points -- in this example, 96. Determine for each flow the number of larger flows that have been measured. For example 80 l/sec is exceeded 55 times. In percentage terms this exceedance is (55/96 x 100) = 57.3%.

Repeat this procedure for other selected flows.

Flow L/sec	% exceedance
30	93.7
50	76.0
80	57.3
100	50.0
150	29.1
200	15.6
300	5.2

The plot of this percentage exceedance data is shown on Figure 2.

C

TYPES OF HYDRAULIC TURBINES

There are two general classes of hydraulic turbines, "impulse" and "reaction" which are distinguished on the basis of how the potential energy of water is converted into mechanical power.

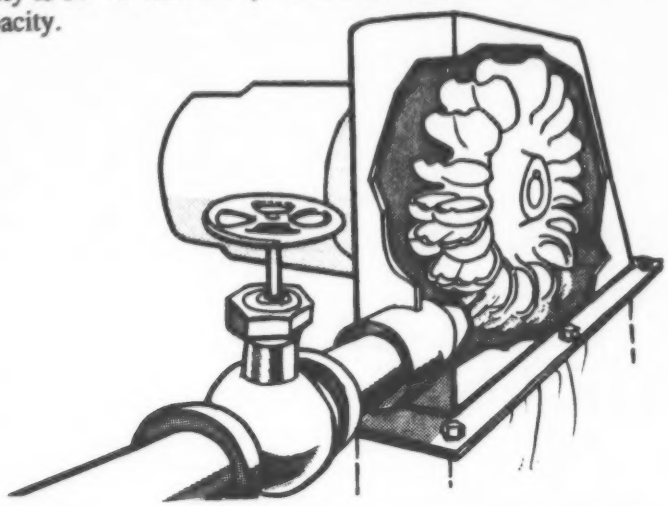
Impulse Turbines

The use of impulse turbines is generally restricted to high head sites -- usually over 20 metres -- though some of the more recent designs can be used with heads as low as 3 metres. Impulse turbines maintain their relatively high efficiency as flow drops below the design flow. In addition, their simple design makes them relatively inexpensive and reliable.

There are three basic types of impulse turbines: Pelton Wheel, Turgo, and Crossflow (Figure C.1). Each uses a high-velocity stream of water to turn the turbine wheel, or runner, which is attached to the turbine shaft and electrical generator.

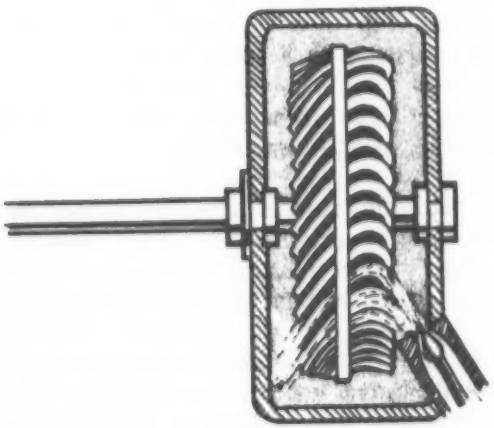
The Pelton wheel is distinguished from other impulse turbines by the use of dual buckets on each runner blade. Because of the relatively simple flow path of this type of turbine, efficiencies up

to 90 per cent are possible. Although generally uneconomic in low head sites, at heads of 35 metres or more, Pelton wheels are likely to be the least costly of all turbines per kilowatt of installed capacity.



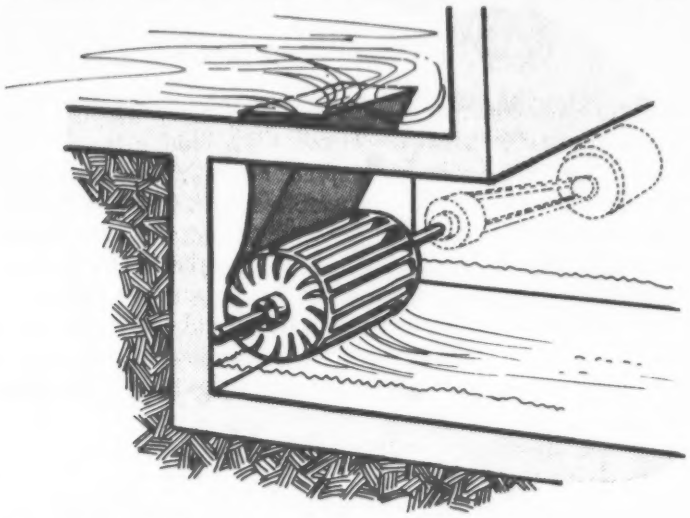
Pelton Wheel

Turgo impulse turbines are slightly more efficient than Pelton turbines -- efficiencies of up to 95 per cent -- and perform well under a wide range of flows, including those as low as 25 per cent of design. Moreover, they can handle up to three times the volume of water of the Pelton and operate with heads as low as 20 metres. Turgo turbines tend to be somewhat more costly than Peltons.



Turgo impuls
turbine

Because their design allows for higher flows, crossflow turbines can operate at significantly lower heads than either the Pelton or turgo turbines -- as low as 3 metres. However, because of their more complex flow path, they are somewhat less efficient than other turbines -- typically in the order of 75 per cent. The cost of crossflow turbines is comparable to that of other turbine types.

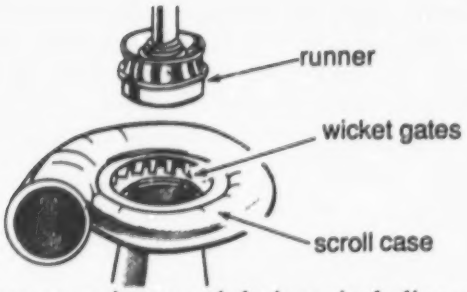


Cross-flow turbine

Reaction Turbines

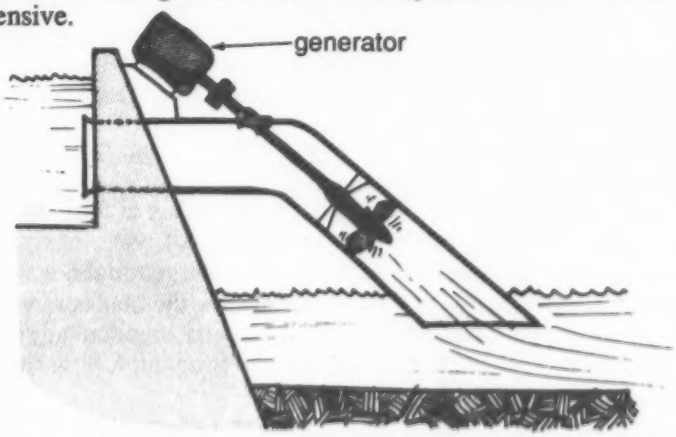
Reaction turbines differ from impulse turbines in that they make use of the pressure as well as the velocity of water to rotate the runner. The blades of the runner are submerged in the water, and power is transferred by water flowing over the blades rather than by striking each blade. Because they can accomodate higher flow rates, reaction turbines are suited to low head, high flow sites.

There are two main types of reaction turbines, referred to as "Francis" and "propeller" (Figure C.2). The Francis turbine is one of the oldest and most commonly used designs for small hydro installations. These turbines operate efficiently over a relatively wide range of head and flow conditions and can be installed in either a horizontal or vertical position. In both cases, water enters perpendicularly to the turbine shaft and turns 90 degrees within the runner enclosure before being discharged parallel to the shaft.



Francis turbine

Propeller turbines come in several designs, including ones with fixed and adjustable blades. Those with blades that adjust automatically are referred to as "Kaplan" turbines. The efficiency of propeller turbines without adjustable blades falls off rapidly under conditions of increased or decreased flow, whereas Kaplan turbines maintain a relatively high efficiency over a much wider range of flows. Because of the high flow characteristics of propeller turbines, they can be used in installations with heads as low as 2 metres. The cost of propeller turbines is similar to that of other turbine designs, but those with adjustable blades are more expensive.



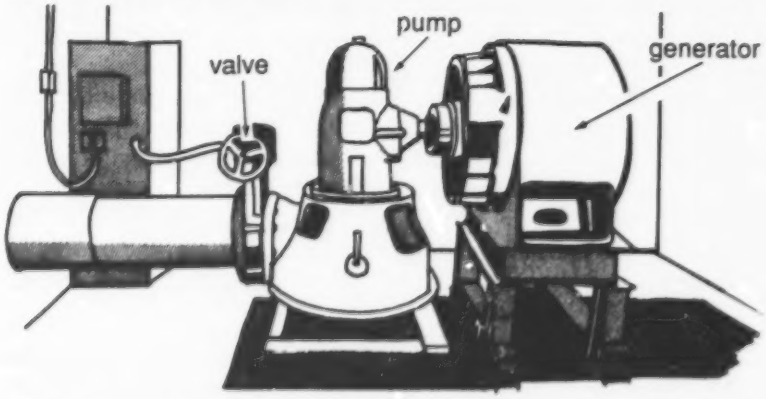
propeller turbine

Tube or tubular turbines are propeller turbines that are mounted horizontally or on a slant. These turbines have fixed or adjustable pitch blades and come with or without wicket gates. The efficiency of tube turbines is slightly higher than that of vertical propeller turbines of the same size, and the performance range of tube turbines with adjustable blades and without wicket gates is greater than for fixed blade units but less than for a Kaplan turbine.

Bulb turbines are propeller turbines in which the blades are directly connected to the generator. The generator is contained within a water-tight enclosure located in the water passage. Bulb turbines also come with fixed and adjustable blades and with and without wicket gates, and their efficiency is similar to that of other propeller turbines.

Pumps as Turbines

A centrifugal pump may be used as a hydraulic turbine when flow through the pump is reversed, that is, when water enters the discharge nozzle and is expelled out the intake nozzle. Because pumps are available in many sizes and manufactured in large quantities, they may be less costly than hydraulic turbines. The choice of using a pump as a turbine should be determined on the basis of the cost of equipment, operating efficiency, life expectancy, and the value of the electricity produced by the pump-turbine compared with that of another turbine under similar head and flow conditions.



pump as a turbine

For a pump used as a turbine to operate at rated speed, the operating head and flow rate must be increased over rated head and flow for normal pumping duty. If the turbine performance curve for a pump is unavailable, a correction factor must be applied to the pump performance curve to determine turbine performance. For pumps operating at speeds of up to 3,500 rpm, these factors range from 1.1 to 2.5 for head and flow respectively and from 0.90 to 0.99 for efficiency. These factors should be developed in consultation with the pump manufacturer. Pump

manufacturers often treat correction factors as proprietary information. Where these data are not available, the developer may have to provide the manufacturer with information on head, flow, and capacity so that the latter can recommend the proper size of pump for the site. A performance curve for a pump operating as a turbine may also be available from the manufacturer and should be obtained.

Consideration should also be given to the stress that may be generated on pump and generator bearings by operating the pump in turbine mode. Because pumps are not specifically designed for turbine duty, this stress could result in premature failure or in excessive wear of either the pump or the generator. The manufacturer should also be consulted on the suitability of pumps for turbine duty.

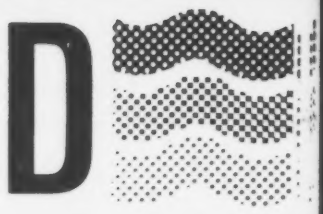
Pumps have no provision for the installation of valves to regulate flow. For a pump to operate efficiently as a turbine, the rate of flow must not vary significantly from design flow. Use of a single pump turbine should be restricted to those sites where flow is more or less constant.

A draft tube -- a gradually enlarging tube between the turbine runner and the tailrace -- must be added to the turbine discharge where a pump is used as a turbine. Several pump manufacturers will add a custom draft tube for turbine application.

Table C.1 summarizes the general characteristics of the hydraulic turbine types.

TABLE C.1

TURBINE	MINIMUM HEAD REQUIREMENTS	SUITABILITY VARYING FLOW CONDITIONS	EFFICIENCY RANGE (AT DESIGN FLOW)
Pelton	23 m	Good	80 - 90%
Turgo	20 m	Good	80 - 95%
Crossflow	3 m	Moderate	60 - 85%
Francis	2 m	Poor	80 - 90%
Propeller	2 m	Moderate	80 - 95%
Kaplan	2 m	Good	80 - 90%



EXAMPLES OF ECONOMIC ANALYSIS

Case One

A farmer decides to install a micro hydroelectric generating plant using an existing dam located on his property. The plant displaces all of the farm's utility purchases at an average price of $0.050 per kWh and excess electricity is sold to the utility on an "at will" basis for $0.023 per kWh. The following assumptions apply:

1) 15kW plant @ 75% capacity factor

2) annual energy output - 98,550kWh
   internal use - 70,000kWh (@ $0.050/kWh)
   external sales - 28,550kWh (@ $0.023/kWh)

3) capital cost of $30,000.00 ($2,000.00/kW capacity)

4) operating and maintenance cost of $270.00 per year

5) financing - $30,000.00 @ 14% for 15 years

6) inflation rate - 6% per year
   electricity price increase - 8% per year
   discount rate of 12%

7) no credit or charge for capacity

Estimating Annual Revenues

Annual energy output (kWh)	=	plant output (kW) x capacity factor x 8760
	=	15 x 0.75 x 8760
	=	98,550kWh
Total annual revenues	=	cost savings from displacement + revenue from sales
Cost savings from displacement	=	internal consumption (kWh) x purchase price
	=	70,000 x $0.050
	=	$3,500.00
Revenue from sales	=	external sales (kWh) x sale price
	=	28,550 x $0.023
	=	$656.65
Total annual revenues therefore	=	$3,500.00 + $656.65
	=	$4,156.65

N.B.: There are no capacity charges or credits applicable in this case since it is assumed that the farm's electrical demand is less than 50kW and that all electricity is sold to the utility on an "at will" basis.

Estimating Annual Costs

Annual mortgage payments	=	amount of loan divided by interest factor (see Table 1)
	=	$30,000/6.1422
	=	$4,884.24

Annual operating expenses for the first year are $270.00 by assumption.

Cost Benefit Analysis: Cash Flow

Year	Revenues (+8% yr)	Operating Expenses (+6% yr)	Loan Repayment	Total Expenses	Net Profit (Loss)	Accumulated Profit (Loss)
1	4042.45	270.00	4884.24	5154.24	(1102.79)	(1102.79)
2	4365.85	286.20	4884.24	5170.44	(804.59)	(1907.38)
3	4715.11	303.37	4884.24	5187.61	(472.50)	(2379.88)
4	5092.32	321.57	4884.24	5205.81	(113.49)	(2493.37)
5	5499.71	340.87	4884.24	5225.11	274.60	(2218.77)
6	5939.68	361.32	4884.24	5245.56	694.12	(1524.65)
7	6414.86	383.00	4884.24	5267.24	1147.62	(377.03)
8	6928.05	405.98	4884.24	5290.22	1637.83	1260.80
9	7482.29	430.34	4884.24	5314.58	2167.71	3428.51
10	8080.88	456.16	4884.24	5340.40	2740.48	6168.99
11	8727.35	483.53	4884.24	5367.77	3359.58	9528.57
12	9425.53	512.54	4884.24	5396.78	4028.75	13557.32
13	10179.57	543.29	4884.24	5427.53	4752.04	18309.36
14	10993.94	575.89	4884.24	5460.13	5533.81	23843.17
15	11873.45	610.44	4884.24	5494.68	6378.77	30221.94
16	12823.33	647.07	paid off	647.07	12176.26	42398.20
17	13849.20	685.89	——	685.89	13163.31	55561.51
18	14957.13	727.05	——	727.05	14230.08	69791.59
19	16153.70	770.67	——	770.67	15383.03	85174.62
20	17446.00	816.91	——	816.91	16629.09	101803.71

Cost Benefit Analysis: Net Present Value

Step Five: Determine present value of the benefits and costs of the project

Year	Revenue	Expenses	Discount Factor (Table 7.3)	Net Present Value Revenues	Expenses
1	4042.45	5154.24	0.8929	3609.50	2857.78
2	4365.85	5170.44	0.7972	3480.45	2564.40
3	4715.11	5187.61	0.7118	3356.21	2301.91
4	5092.32	5205.81	0.6355	3236.17	2066.73
5	5499.71	5225.11	0.5674	3120.54	1856.20
6	5939.68	5245.56	0.5066	3009.04	1667.66
7	6414.86	5267.24	0.4523	2901.44	1498.72
8	6928.05	5290.22	0.4039	2798.24	1347.63
9	7482.29	5314.58	0.3606	2698.11	1211.94
10	8080.88	5340.40	0.3220	2602.04	1090.52
11	8727.35	5367.77	0.2875	2509.11	981.55
12	9425.53	5396.78	0.2567	2419.53	883.84
13	10179.57	5427.53	0.2292	2333.16	796.21
14	10993.94	5460.13	0.2046	2249.36	717.42
15	11873.45	5494.68	0.1827	2169.28	646.94
16	12823.33	647.07	0.1631	2091.48	105.54
17	13849.20	685.89	0.1456	2016.44	99.86
18	14957.13	727.05	0.1300	1944.43	94.52
19	16153.70	770.67	0.1161	1875.44	89.47
20	17446.00	816.91	0.1037	1809.15	84.71
				$52229.12	$22963.55

The net present value of the project = total discounted revenues
minus
total discounted costs.
= $52,229.12 - 22,963.55
= $29,265.57

The project looks economically feasible.

Case Two

A municipal electrical utility is investigating the feasibility of installing a 920kW turbine at an existing dam site. All the energy produced would be used to offset bulk electricity purchases from another utility.

The value of the power produced is assumed to be the same as the utility's cost of buying power from another utility. This "wholesale" price consists of a demand or capacity charge of $10.18 per kW of demand and an energy charge of $0.0154 per kWh of electricity purchased.

In this example, it is assumed that there will be insufficient flow in some months (July, August and September) to operate the plant at full-rated capacity. However, the flow is sufficient to operate the plant at full capacity for nine months and at reduced capacity for three months.

Assumptions

1) 920kW plant at 82% annual capacity factor (the plant is assumed to be unavailable an equal amount of time each month)
2) capital cost of $1,472,000.00 ($1,600/kW)
3) annual operating and maintenance cost of $12,700.00
4) financing - $1,472,000.00 @ 14% for 15 years
5) inflation - 6% per year
   electricity price increase - 8% per year
   discount rate - 12% per year
6) operation of the plant meets all requirements of the wholesale utility

Estimating Annual Revenues

Annual Energy Output

The following table provides a summary of plant capacity for each month of the year, as determined by available flow.

MONTHLY PLANT CAPACITY (kW)

January	920	May	920	September	800
February	920	June	920	October	920
March	920	July	870	November	920
April	920	August	840	December	920

Since plant capacity varies by month, annual energy output must be calculated on the basis of average available plant capacity. Average annual plant capacity can be found by dividing the sum of plant capacity for each month by the number of months in a year.

Average annual capacity $= \frac{920 + 920 + ... + 920}{12} = 899\text{kW}$

Annual energy output (kWh) = average annual capacity factor x 8760 (number of hours in a year)
= 899 x 0.82 x 8760
= 6,457,696 kWh

Total annual revenues = cost savings from displacement (energy capacity) + revenue from sales
= (6,457,696 x $0.0154) + (899 x $10.18 x 12)
= ($99,448.52 + $109,821.84)
= $209,270.36

To be more conservative, electrical production for only 10 or 11 months could be used. This would take into account the small hydro plant being out of service at the time of the peak one or two months of the year.

There are no revenues from sales.

Total revenues, therefore = $209,270.36

Estimating Annual Costs

Annual mortgage payments = amount of loan divided by interest factor (see Table 1)
= $1,472,000/6.1422
= $239,653.54

Annual operating expenses for the first year are $12,700 by assumption.

Cost Benefit Analysis: Cash Flow

Year	Revenues (+8% yr)	Operating Expenses (+6% yr)	Loan Repayment	Total Expenses	Net Profit (Loss)	Accumulated Profit (Loss)
1	209270.0	12700	239653.54	252353.5	(43083.5)	(43083.5)
2	226011.6	13462	239653.54	253115.5	(27103.9)	(70187.4)
3	244092.5	14270	239653.54	253923.5	(9832.0)	(80018.4)
4	263619.9	15126	239653.54	254799.5	8840.36	(71178.1)
5	284709.9	16033	239653.54	255686.5	29023.36	(42154.7)
6	307486.2	16995	239653.54	256648.5	59837.66	8683.0
7	332085.1	18015	239653.54	257668.5	74416.56	83099.6
8	358652.0	19096	239653.54	258749.5	99902.46	183002.0
9	387344.1	20242	239653.54	259895.5	127448.56	310450.5
10	418331.6	21456	239653.54	261109.5	157222.06	467672.6
11	451798.2	22744	239653.54	262397.5	189400.70	657073.3
12	487942.0	24109	239653.54	263761.5	224180.46	881253.8
13	526997.4	25555	239653.54	265208.5	261768.86	1143022.6
14	569135.4	27088	239653.54	266741.5	302393.86	1445416.5
15	614666.5	28713	239653.54	268366.5	346299.96	1791716.5
16	663839.8	30436	——	30436.5	633403.50	2425120.0
17	716947.0	32262	——	32262.5	684684.50	3109804.5
18	774302.7	34198	——	34198.2	740104.50	3849909.0
19	836247.0	36250	——	36250.1	799996.90	4649905.9
20	903146.7	38425	——	38425.1	864721.60	5514627.5

Cost Benefit Analysis: Net Present Value

Year	Revenue	Expenses	Discount Factor (Table 7.3)	Net Present Value Revenues	Expenses
1	209270.00	252353.50	0.8929	186857.18	225326.44
2	226011.60	253115.50	0.7972	180176.45	201783.68
3	244092.50	253923.50	0.7118	173745.04	180742.75
4	263619.90	254799.50	0.6355	167530.45	161925.08
5	284709.90	255686.50	0.5674	161544.40	145076.52
6	307486.20	256648.50	0.5066	155772.51	130018.13
7	332085.10	257668.50	0.4523	150202.09	116543.46
8	358652.00	258749.50	0.4039	144859.54	104508.92
9	387344.10	259895.50	0.3606	139676.28	93718.32
10	418331.60	261190.50	0.3220	134702.78	84077.26
11	451798.20	262397.50	0.2875	129891.98	75439.28
12	487942.00	263761.50	0.2567	125254.71	67707.58
13	526977.40	265208.50	0.2292	120783.22	60785.79
14	569135.40	266741.50	0.2046	116445.10	54575.31
15	614666.50	268366.50	0.1827	112299.57	49030.56
16	663839.80	30436.30	0.1631	108272.27	4964.16
17	716947.00	32262.00	0.1456	104387.48	4697.34
18	744302.70	34198.20	0.1300	96759.35	4445.77
19	836247.60	36250.10	0.1161	97088.35	4208.64
20	903146.70	38425.10	0.1037	93656.31	3984.68
				$2699904.70	$1773559.70

The net present value of the project = total discounted revenues
minus
total discounted costs
= $269,904.70 -
1,773,599.70
= $926,345.00

This project looks like a good investment.

E

CANADIAN UTILITY POLICIES ON PRIVATE GENERATION

INTRODUCTION

In general, provided that technical and legal requirements can be satisfied, most provincial utilities will allow interconnection. Of those utilities which do permit interconnection, each one exercises a discretionary right to limit or reject potential parallel generators. There are many issues relevant to the topic of interconnection. For example, the right to wheel should be considered. The wheeling of electric power is defined as the transmission of electric power from a seller to a remote purchaser over facilities owned by an intermediate party. None of the utilities surveyed has a policy for wheeling. In provinces where wheeling does occur, agreements are drawn up on a case-by-case basis between the private generator and the utility involved. Each of these agreements contains specific charges. Rates of payment to parallel generators for energy produced are established by provincial utilities and may provide for blended rates. A blended rate combines payment for energy and capacity. Metering requirements also become relevant when examining private generation.

Most of the provincial public utilities are prepared to offer technical advice of a general nature when approached by potential parallel generators, but none is actually advertising this service.

Work beyond the general feasibility stage is usually performed by private sector consultants. Each utility will review and evaluate proposals, and a few such as Saskatchewan and B.C., will further provide technical information, evaluation methods plus lists of known suppliers and manufacturers. All are treating their first few installations as an experimental phase from which a more permanent, long-term policy can be derived. All of these issues, relevant to parallel generation, will be discussed in detail below.

UTILITY POLICIES

Newfoundland Light and Power

In Newfoundland, an individual has the right to connect to the electrical grid to sell power to Newfoundland Light and Power. The utility purchases electricity from Newfoundland and Labrador Hydro and from a 1.5kW windmill. The rate paid for energy is roughly 2.83¢/kWh, which is based on the avoided cost calculation of alternatives. Two and three party wheeling is allowed, with charges based on the avoided cost for the customer. No blended rates are offered, nor is payment made for capacity. The residential end rate is 4.72¢/kWh plus a fuel adjustment clause. The metering requirements are standard: 2 meters measuring kilowatt hours are used -- 1 buy and 1 sell. The private generator pays for the costs of the "sell" meter. Newfoundland offers subsidies through the Federal-Provincial Conservation and Renewal Energy Demonstration Assistance (CREDA) Agreement for demonstrations.

Maritime Electric Co. Ltd.

The Maritime Electric Co. Ltd. in Prince Edward Island will buy electricity from an interconnected parallel generator, but at present only a negligible amount of this is done. There are a couple of wind generators, a bio-gas and a methane generator. (A municipal solid waste plant is being planned in Prince Edward Island, where electricity costs are particularly high.) The rate paid to a private generator is about 6¢/kWh, varying monthly based on incremental costs. The rate calculation is a function of the avoided cost adjusted for system loss. No blended rates are offered by the Maritime Electric Co. Ltd. The utility does not pay for capacity. The residential end rate is 11.7¢/kWh. Two meters are required --

1 buy and 1 sell, with the customer paying all additional costs. Wheeling of electricity is not permitted by the utility.

Nova Scotia Power

In Nova Scotia, purchasing electricity from parallel generators accounts for only a very small percentage of the power supply. Only four installations exist in the province, the largest being 250kW, and there are two windmills. Good rates (6.27¢/kWh) are offered for hobby size (<10kW) generators. So far no very small generators have taken advantage of this offer. The rate for this type of generator is based on the residential end rate. For parallel generators in the 10kW-15 MW range, the rate is 70 per cent of the hourly marginal. For a 250kW installation, this is set monthly at 1.9¢/kWh. For any facility greater than 15 MW the rate is negotiated between the Nova Scotia Power Corporation and the private generator. There is no credit offered for capacity. In the future, time-of-day rates and reduction of the present capacity surplus may lead to a credit for capacity and an adjustment to the present energy pricing policy. Wheeling of electric power is not permitted by the Nova Scotia Power Corporation. The utility requires 2 meters to interconnect -- 1 buy and 1 sell. The utility pays for 1 meter, installation and reading. The customer pays any costs in addition to regular costs. Nova Scotia has a Federal-Provincial small scale Energy Demonstration Project Program administered by Nova Scotia Department of Mines and Energy.

New Brunswick Electric Power Commission

The New Brunswick Electric Power Commission permits interconnection with the grid. The rate paid for electricity to a private generator averages 3-3.5¢/kWh as a function of the value of generation replaced. For in-province generation purchases, the rate is calculated according to one of two categories. For dedicated supply (customer has no load and delivers total net production to N.B. Power) the rate is 70 per cent of the value of generation replaced. For surplus energy supply (customer sells only their surplus energy after meeting their own needs) the rate is 85 per cent of the dedicated rate or 59.5 per cent of the value of generation replaced. No provision has been made for blended rate structures. The residential end rate is 4.27¢/kWh. No wheeling provisions exist in New Brunswick. The New Brunswick Electric

Power Commission requires 2 meters -- 1 buy and 1 sell -- with the customer paying for anything not usually required.

Hydro Quebec

Quebec is presently examining the feasibility for allowing interconnection. Quebec does have, in the case of large power producers such as Alcan and MacLaren, what is termed an "interconnection convention" which treats each as a separate utility. Agreement between the two parties is struck on the same basis as, for instance, Ontario and Quebec Hydros. They exchange power and grant compensation to one another depending on needs. Until very recently, sales of private power were essentially not allowed in Quebec. Hydro Quebec is now developing policy and rates that are expected to be similar to Ontario Hydro's.

Ontario Hydro

As long as technical and legal requirements are met, Ontario Hydro will allow interconnection with the provincial grid. Ontario Hydro has established a rate structure which more accurately reflects the value of parallel generation compared to future generating capacity which Ontario Hydro would have to provide. Hydro pays 3.3¢/kWh for power from generators which run at least 65 per cent of the time each month. Generators with monthly capacity factors of less than 65 per cent are paid 2.3¢/kWh. The rate calculation is based on 85 per cent of the wholesale price of power. The residential end rate is 4.88¢/kWh. Ontario Hydro pays for capacity and offers a blended rate. Ontario does not have a policy concerning wheeling of electric power, but Ontario Hydro allows wheeling of electric power from one location to service another location both owned by the same individual or group. However, Ontario law forbids electricity sales by private individuals in an enfranchised jurisdiction.

All purchases are restricted to public utilities or Ontario Hydro. Sales to a third party are allowed outside of municipal enfranchised areas. Wheeling charges are based on the incremental distribution system costs. Metering requirements vary depending on the size of the installation. For a generator less than 100 kW, unidirectional demand/energy metering is installed. Ontario Hydro

covers the cost of metering. Ontario has provided funds under the Canada-Ontario CREDA Agreement for demonstrations.

Further information on Ontario Hydro's rates and service conditions are provided at the end of this Appendix.

Manitoba Hydro

In Manitoba, an individual has the right to interconnect to the grid to sell power to Manitoba Hydro. The energy produced is credited against the energy consumed by the customer. The residential end rate is 3.175/kWh. The rate paid for energy by Manitoba Hydro to a private generator varies depending on the size of the installation involved. For a generator less than 20kW there are three separate categories. A residential customer (as in the three rural farm installations) is paid 3.175¢/kWh. A general service (<50kVA) customer is paid 3.666¢/kWh. A power customer (>50kVA) is paid 1.407¢/kWh. For a generator greater than 20kW the rate paid is negotiated. No blended rates are offered, nor is payment for capacity made. There is not a great deal of interconnection in Manitoba. Wind turbines in existence are less than 20kW. There is one experimental wind turbine of 50kW, but it is out of operation 50-60 per cent of the time. Manitoba has no instances of wheeling, but would likely permit an individual or group to wheel to supply load requirements elsewhere in the system. Third party involvement would not likely be granted. In cases of possible conflict, the reliable operation of the provincial grid would take precedence. Metering requirements vary according to installation size. For a generator less than 20kW bidirectional kWh meters which spin backward are required. For installations greater than 20kW "in" and "out" meters are installed. The utility provides one meter, and the customer provides the rest.

Saskatchewan Power Corporation

The Saskatchewan Power Corporation (SPC) will purchase electricity from an interconnected parallel generator. However, the utility does not pay the generator directly, but instead credits their account for excess electrical energy fed back into SPC's system. The net consumption for which the customer is charged equals the total electrical energy drawn from the system, less generation fed back into the system. The amount billed is based on SPC's standard rates. There are no other rate provisions available. A

small number of wind-driven electrical generation devices operate in Saskatchewan, along with a gas turbine which uses excess gas from the wells of an oil field. The residential end rate is 4.42¢/kWh and there are no blended rates offered. In Saskatchewan no provisions exist for wheeling of electric power. The SPC requires bidirectional metering where energy flows both ways. There is a kWh meter to register production, and a demand meter. The utility supplies, installs and reads the meter. The customer provides the socket, instrument and meter enclosure. Saskatchewan provides funds under the Canada-Saskatchewan Renewables Conservation Demonstration Agreement.

Alberta Power Ltd.

In Alberta, an individual or group can connect generating equipment to the system providing all requirements of the Alberta Electric Protection Act and Canadian Electric Code are met and it does not degrade the level of service to other customers. The basis for the rate paid for small power producers is related to the customer's incremental cost of generation, but shall not exceed the cost of equivalent capacity and energy from the utility's system. Capacity and energy charges are included in the rate, but are not separated in a demand energy rate.

Presently there are no small power producers in Alberta, and, therefore, a specific rate has not been determined. Alberta Power's average residential rate is about 6¢/kWh. There are no provisions for wheeling made in Alberta. For small power producers no special metering would likely be required; a basic 1 "buy" and 1 "sell" meter would suffice. Any special metering for utility research purposes would be paid for by the utility. In Alberta, the Department of Energy and Natural Resources provides funds out of the Alberta-Canada Energy Resources Research Fund.

Transalta Utilities

Transalta Utilities in Alberta permits exchanges of power between their system and a private generator. Banking of energy is also allowed, where the windmill, for example, generates energy and banks it to draw on later. For installations less than 100kW, energy consumed is credited against energy produced. If net energy is sold to the system, the utility will pay the parallel

generator on the basis of avoided cost. The rate paid to a private generator by Transalta Utilities averages about 1.6¢/kWh. The residential end rate or farm energy rate is 4.4¢/kWh. No blended rates are offered, and payment for capacity is presently under review. There are no provisions for wheeling in Alberta. Experimental meters taking time-of-day readings are paid for by the utility. The parallel generator pays for the buy and sell meters used for the calculation of revenue.

British Columbia Hydro

British Columbia Hydro now has contracts with three small parallel generators. Recently the province has found itself in a situation of increasing surplus electric power. While British Columbia Hydro is honouring commitments made to the three customers concerning electric power purchases, it is advising other interested parties that it cannot justify buying their electric power due to the system surplus. Therefore there is no advantage to interconnection at this time. British Columbia has a policy of support for parallel generation, but no subsidization -- electricity will be purchased only if it is economical. British Columbia Hydro further suggests that while the surplus remains developers may refine their generation proposals, select their equipment, etc.; the utility is willing to advise and work with potential parallel generators in order to ensure efficient future purchases.

British Columbia Hydro is in the process of developing a policy for purchase of electricity in non-integrated areas served by diesel generation. The rate conditions applicable to such purchases would differ from those applicable on the integrated system. In British Columbia, the rates paid to parallel generators are based on the end rate of whatever retail consumption rate they are paying. This is the trailing or end step rate at which the balance of electrical energy consumed above a certain level is paid. This varies according to voltage level, but is about 2¢/kWh or higher. Since British Columbia is in a surplus electric power situation, it is quite possible that these same rates will remain in effect. The residential end rate is 4.5¢/kWh and no blended rates are offered. There are no provisions for wheeling of electric power in British Columbia. The utility requires 2 meters to interconnect -- 1 buy and 1 sell. The utility provides the meter and the generator pays all costs on its side of metering.

Explanation of Headings

Table of Parallel Generation

Parallel Generation	Electricity generation not owned or controlled by a utility, but connected to the utility power system.
Jurisdiction	The utility.
Right to Connect	The utility allows a private generator to connect.
Right to Wheel	Use of utility lines to move power. Three party wheeling is sale of power between a private generator and a private power user. Power is delivered over the electrical transmission system of the utility. Two party wheeling is similar but the generator and the user of the power are owned by the same party. The utility lines are used to move the power.
Charges	For wheeling (only applies in Ontario, 0.7¢ per kWh for short distance).
How is rate calculated	This is calculation of rate paid for purchased power.
Blended Rate	A capacity credit is included in price paid for energy.
Payment for Capacity	Payment for kW's as well as kWh's.
Rate Paid for Energy	Purchase rate.
Residential End Rate	Last block (least expensive) power sold to residential customers by utility.
Metering Requirements	Utility policy for metering private generation selling into the system.
Who Pays for Metering	Utility/Private generator: who pays the costs?

Utility Policies on Private Generation

Newfoundland Light and Power

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes at present buy from Nfld. and Labrador Hydro and from 1 windmill only.	2 3 PARTY No No	The purchase price will be related to the avoided cost of energy for the Company.	In future, the purchase price will be tied to price paid to Nfld. Hydro for firm power.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
Dependent on size and type of installation.	In future, it will be tied to purchase price from Nfld. Hydro (currently 2.833¢/kWh) plus fuel adjustment clause.	4.72¢/kWh + fuel adjustment clause.	2 meters -- 1 buy and 1 sell.	Generator will pay all costs above normal installation.

Maritime Electric Co. Ltd.

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	N/A	Avoided cost adjusted for system loss.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No	About 6¢/kWh, varies monthly based on incremental cost.	11.7¢/kWh	2 meters -- 1 buy and 1 sell	Customer pays all additional costs.

Hydro Quebec

RIGHT TO CONNECT.	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Not at present. Under review.	2 3 PARTY N/A N/A	N/A	N/A	N/A

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
N/A	N/A	3.71¢/kWh	N/A	N/A

Nova Scotia Power

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	N/A	a) <10kW: residential end rate b) 10kW-15MW: 70% of marginal rate. c) >15MW: negotiated.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No	a) <10kW: 6.27¢/kWh b) >10kW:70% of hourly marginal set monthly at 1.9¢/kWh (for a 250 kW installation).	6.27¢/kWh	2 meters -- 1 buy and 1 sell.	Utility pays for 1 meter, installation and reading; customer pays for what is not usually needed.

New Brunswick Electric Power Commission

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	N/A	a) Dedicated supply -- (customer has no load and delivers total net production to N.B. Power) - 70% of the value of generation replaced. b) Surplus energy supply -- (customer sells only their surplus energy after meeting their own needs) - rate is 85% of the dedicated rate or 59.5% of the value of generation replaced.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No	Averages 3-3.5¢/kWh as a function of value of generation replaced.	4.27¢/kWh	2 meters -- 1 buy and 1 sell	Customer pays for anything not usually required.

British Columbia Hydro

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Suspended due to surplus.	2 3 PARTY No No	N/A	Based on trailing rate for class of service. Varies according to voltage level.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No	About 2¢/kWh or higher.	4.5¢/kWh	2 meters - 1 buy and 1 sell.	Utility provides meter. Generator pays all costs on generator side of metering.

Ontario Hydro

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	Based on incremental distribution system costs.	85% of the wholesale price of power.	Yes

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
Yes	a) <65% capacity factor = 3.3¢/kWh b) >65% capacity factor = 2.3¢/kWh	4.88¢/kWh	If <100kW, and on blended rate, uni-directional kWh metering is installed. >100kW, unidirectional demand/energy metering is installed.	Utility pays.

Alberta Power Ltd.

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No		Based on customer's incremental cost of generation, but shall not exceed the cost of equivalent capacity and energy from the company's system.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No	No rate available, because at present no small power producers inter-connected.	6.00¢/kWh	2 meters - 1 buy and 1 sell.	Depends on contract. Special metering for utility research purposes would be paid for by the utility.

Saskatchewan Power Corporation

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	N/A	Energy produced is credited against energy consumed by customer.	N/A

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
N/A	No rate available as customer credited on billing.	4.42¢/kWh	Bidirectional meter - energy flows both ways; kWh meter register production, demand meter.	Utility supplies, installs and reads meters. Customer provides socket, instrument and meter enclosure.

Manitoba Hydro

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	N/A	Energy produced is credited against energy consumed by customer.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No	a) ≤20kW: 3.175¢/kWh if residential (as in 2 rural farm installations) - general service customer paid 3.666¢/kWh (>50kVA); - power customer (>50kVA) paid 1.407¢/kWh. b) ≥20kW: negotiated.	3.175¢/kWh	a) ≤20kW: bidirectional kWh meter -- turns backward. b) ≥20kW: 'IN" & 'OUT' meters.	Hydro provides 1 meter, customer provides the rest.

Transalta Utilities

RIGHT TO CONNECT	RIGHT TO WHEEL	CHARGES	HOW RATE IS CALCULATED	BLENDED
Yes	2 3 PARTY No No	N/A	For installations less than 100kWh energy consumed by customer is credited against energy produced. Additional energy is paid for on the basis of avoided cost.	No

PAYMENT FOR CAPACITY	RATE PAID FOR ENERGY	RESIDENTIAL END RATE	METERING REQUIREMENTS	WHO PAYS FOR METERING
No, but under review.	1.6¢/kWh	4.4¢/kWh farm energy rate.	Experimental meters taking Time of Day reading. 2 meters - 1 buy and 1 sell used for calculation of revenue.	Experimental meter paid for by Utility. Parallel generator pays for other meters.

CANADIAN UTILITIES

NEWFOUNDLAND LIGHT & POWER CO. LTD.
P.O. BOX 8910
55 Kenmount Road
St. John's, Newfoundland
A1B 3P6
(709) 737-5600

ALBERTA POWER
P.O. Box 2426
10035 - 105 Street
Edmonton, Alberta
T5J 2V6
(403) 420-7627

NEW BRUNSWICK ELECTRIC POWER COMMISSION
P.O. Box 2000
Fredericton, New Brunswick
E3B 4X1
(506) 453-4444

MARITIME ELECTRIC CO. LTD.
Box 1328, 134 Kent Street
Charlottetown, Prince Edward Island
C1A 7N2
(902) 566-1599

NOVA SCOTIA POWER CORP.
P.O. Box 910
Halifax, Nova Scotia
B3J 2W5
(902) 428-6907

MANITOBA HYDRO
820 Taylor Avenue
P.O. Box 815
Winnipeg, Manitoba
R3C 2P4
(204) 474-3311

ONTARIO HYDRO
700 University Avenue
Toronto, Ontario
M5G 1X6
(416) 592-3727

B.C. HYDRO
970 Burrard Street
Vancouver, British Columbia
V6Z 1Y3
(604) 663-2692

QUEBEC HYDRO
75 Dorchester Blvd. West
Montreal, Quebec
H2Z 1A4
(514) 289-2843

TRANSALTA UTILITIES
110 - 12th Avenue S.W.,
Box 1900
Calgary, Alberta
T2P 2M1
(403) 267-7110

SASKATCHEWAN POWER
2025 Victoria Avenue
Regina, Saskatchewan
S4P 0S1
(306) 566-2121

ONTARIO HYDRO'S RATES AND SERVICE CONDITIONS

Parallel Generation Interconnection Requirements

Ontario Hydro's interconnection requirements apply to any developer who will be supplying electricity to Ontario Hydro's distribution system.

The conditions of agreement mentioned here do not necessarily apply to installations located within the service area of an electrical utility other than Ontario Hydro. The developer should consult the utility concerned for appropriate direction.

Detailed plans of the project must be submitted to the local Ontario Hydro Regional Marketing Department for approval. A list of the regional offices is provided in Table E.1. These offices can give you detailed information on interconnection requirements.

ENERGY RATES AND ADMINISTRATION CHARGES

As of January 1, 1986, the following rates and charges applied to Ontario Hydro's parallel generators:

- **Standard Energy Rates**

  For capacity factors of 65% or greater - 3.45 cents per kWh
  For capacity factors below 65% - 2.45 cents per kWh
  based on the rated kilowatt capacity of the generator or the measured kilowatts delivered in the month.

- **Optional Rates - for generators with capacities of 250 kWh or greater**

  Capacity Rates

Winter	$7.30 per kW per month
Summer	$3.65 per kW per month

  as measured during the peak period of the month. No capacity payment will be made in any month that the capacity factor is below 65%.

  Energy rates

Winter peak	2.92 cents per kWh
Winter off-peak	2.33 cents per kWh
Summer peak	2.56 cents per kWh
Summer off-peak	1.60 cents per kWh

  Times of Use

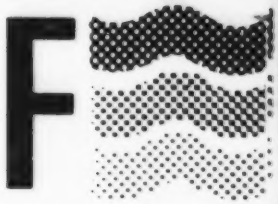
Winter	- October through March
Summer	- April through September
Peak	- 7 a.m. to 11 p.m. weekdays
Off-peak	- 11 p.m. to 7 a.m. weekdays plus all weekends and public holidays

- **Rate for large (5000 kW), at-will generators connected to the Bulk Electricity System, delivering energy on an occasional basis only**

  3.45 cents per kWh multiplied by the capacity factor of the generator for the month of delivery, with a floor price equal to the energy rate applicable to direct customer purchases from Ontario Hydro.

TABLE E.1
ONTARIO HYDRO REGIONAL MARKETING DEPARTMENTS

Region	Address
Central	5760 Yonge Street Willowdale, Ontario M2M 3T7 (416) 222-6502
Eastern	420 Dundas St. East Belleville, Ontario K8N 5C3
Georgian Bay	93 Bell Farm Road Barrie, Ontario L4M 1H1 (705) 728-5521
Northeastern	590 Graham Drive North Bay, Ontario P1B 8L4
Northwestern	34 Cumberland St. North Room 304 Thunder Bay, Ontario P7A 4L5 (807) 344-2411
Western	1075 Wellington Road London, Ontario N6E 1M1 (519) 681-1390



ONTARIO MINISTRY OF NATURAL RESOURCES OFFICES

DISTRICT	ADDRESS	DISTRICT	ADDRESS
Algonquin Park	Box 219 Whitney, Ontario K0J 2M0 (705) 637-2780	Brockville	101 Water St. West Brockville, Ontario K6V 5Y8 (613) 342-8524
Atikokan	108 Saturn Ave. Atikokan, Ontario P0T 1C0 (807) 597-6971	Cambridge	Box 2186 Cambridge, Ontario N3C 2W1 (519) 658-9355
Aylmer	353 Talbot St. West Aylmer, Ontario N5H 2S8 (519) 773-9241	Chatham	Box 1168 435 Grand Ave. West Chatham, Ontario N7M 5L8 (519) 354-7340
Bancroft	Box 500 Bancroft, Ontario K0L 1C0 (613) 332-3940	Chapleau	34 Birch Street Chapleau, Ontario P0M 1K0 (705) 864-1710
Blind River	Box 190 62 Queen Street Blind River, Ontario P0R 1B0 (705) 356-2234	Cochrane	Box 730 2 Third Avenue Cochrane, Ontario P0L 1C0 (705) 272-4365
Bracebridge	Box 1138 Bracebridge, Ontario P0B 1C0 (705) 645-5244		

DISTRICT	ADDRESS
Cornwall	Box 1759 113 Amelia Street Cornwall, Ontario K6H 5V7 (613) 933-1774
Dryden	Ontario Gov't Building Box 3000 Dryden, Ontario P8N 3B3 (807) 223-3341
Espanola	Box 1340 148 Fleming Street Espanola, Ontario P0P 1C0 (705) 869-1330
Fort Francis	922 Scott Street Fort Francis, Ontario P9A 1J4 (807) 274-5337
Geraldton	Box 640 Geraldton, Ontario P0T 1M0 (807) 854-1030
Gogama	Box 129 Gogama, Ontario P0M 1W0 (705) 894-2000
Hearst	Box 670 631 Front Street Hearst, Ontario P0L 1N0 (705) 362-4346
Huronia	Midhurst, Ontario L0L 1X0 (705) 728-2900
Ignace	Box 448 Ignace, Ontario P0T 1T0 (807) 934-2233
Kapuskasing	6 Government Road Kapuskasing, Ontario P5N 2W4 (705) 335-6191
Kirkland Lake	Box 129 Swastika, Ontario P0K 1T0 (705) 642-3222
Kenora	Box 5080 808 Robertson Street Kenora, Ontario P9N 3X9 (807) 468-9841
Lanark	Box 239 Lanark, Ontario K0G 1K0 (613) 259-2942
Lindsay	322 Kent Street Lindsay, Ontario K9V 4T7 (705) 324-6121
Maple	Maple, Ontario L0J 1E0 (416) 832-2761
Minden	Minden, Ontario K0M 2K0 (705) 286-1521
Moosonee	Box 190 Moosonee, Ontario P0L 1Y0 (705) 336-2987
Napanee	1 Richmond Blve. Napanee, Ontario K7R 3S3 (613) 354-2173
Niagara	Box 1070 Hwy. 20 Fonthill, Ontario L0S 1E0 (416) 892-2656

DISTRICT	ADDRESS
Nipigon	Box 970 Nipigon, Ontario P0T 2J0 (807) 887-2120
North Bay	Box 3700 North Bay, Ontario P1B 8K7 (705) 474-5550
Ottawa	Ramsayville, Ontario (613) 822-2525
Owen Sound	611 Ninth Ave. East Owen Sound, Ontario N4K 3E4 (519) 376-3860
Parry Sound	4 Miller Street Parry Sound, Ontario P2A 1S8 (705) 746-2401
Pembroke	Box 220 Riverside Drive Pembroke, Ontario K8A 6X4 (613) 732-3661
Red Lake	Box 323 Hwy. 105 Red Lake, Ontario P0V 2M0 (807) 727-2531
Sault Ste. Marie	Box 130 69 Church Street Sault Ste. Marie, Ontario P6A 5L5 (705) 949-1231
Simcoe	645 Norfolk St. North Simcoe, Ontario N3Y 3R2 (519) 426-7650
Sioux Lookout	Box 309 Sioux Lookout, Ontario P0V 2T0 (807) 737-1140
Sudbury	Box 3500, Stn. A Sudbury, Ontario P3A 4S2 (705) 522-7823
Temagami	Box 38 Temagami, Ontario P0H 2H0 (705) 569-3622
Terrace Bay	Box 280 Terrace Bay, Ontario P0T 2W0 (807) 825-3205
Thunder Bay	Box 5000 Thunder Bay 'F', Ontario P7C 5G6 (807) 475-1501
Timmins	896 Riverside Drive Timmins, Ontario P4N 3W2 (705) 267-7951
Tweed	Metcalfe Street Tweed, Ontario K0K 3J0 (613) 478-2330
Wawa	Box 1160 Wawa, Ontario P0S 1K0 (705) 856-2396
Wingham	R.R. # 5 Wingham, Ontario N0G 2W0 (519) 357-3131

REGIONAL OFFICES

DISTRICT	ADDRESS	DISTRICT	ADDRESS
Algonquin Regional Office	Brendale Square P.O. Box 9000 Huntsville, Ontario P0A 1K0 (705) 789-9611	North Central Regional Office	Ontario Gov't Building 435 James St. South P.O. Box 5000 Thunder Bay 'F', Ontario P7C 5G1 (807) 475-1261
Central Regional Office	10670 Yonge St. North Richmond Hill, Ontario L4C 3C9 (416) 884-9203	Northeastern Regional Office	174 Douglas St. W. Sudbury, Ontario P3E 1G1 (705) 673-1111
Eastern Regional Office	Provincial Gov't Building Concession Road Kemptville, Ontario K0G 1J0 (613) 258-3413	Southwestern Regional Office	1106 Dearness Drive London, Ontario N6E 1N9 (519) 681-5350
Northern Regional Office	140 Fourth Avenue P.O. Box 3000 Cochrane, Ontario P0L 1C0 (705) 272-4287	Northwestern Regional Office	808 Robertson Street Box 5160 Kenora, Ontario P9N 3X7 (807) 468-3111

CANADIAN EQUIPMENT SUPPLIERS

FIRM	TYPE OF EQUIPMENT
Barber Hydraulic Turbine Barber Point P.O. Box 340 Port Colborne, Ontario L3K 5W1	Turbines: Francis, Kaplan, Pelton, Propeller (100 kW to 15,000 kW) Generators: Parallel Gear, Right Angle Gear, Belt Drive
Canadian General Electric Ontario Electric Utility Sales Division 1400 Castlefield Avenue Toronto, Ontario M6B 4C4	Turbines: Francis, Kaplan, Pelton (250 kW to 25,000 kW) Generators: Parallel Gear, Right Angle Gear, Epicyclic Gear
Canbar Inc. Box 280 Waterloo, Ontario N2J 4A7	Penstocks: Wood stave (diameter 60 cm to 550 cm; pressure to 400 ft. head; length 30 m plus)
Dependable Turbine Ltd. Unit 7 3005 Murray Street Port Moodie, B.C. V3H 1X3	Turbines: Francis, Kaplan, Pelton, Turgo (5 kW to 3 MW)

FIRM	TYPE OF EQUIPMENT
D.F.D. Steel Industries Ltd. 1694 Evangeline Road London, Ontario N5W 3G7	Penstocks: Metal (diameter 20 cm to 400 cm; length 1.5 m plus)
Dominion Bridge Sulzer Inc. P.O. Box 555 Lachine, Quebec H8S 4E7	Turbines: Kaplan, Propeller, Francis, Tube-Type (1,000 kW to 10,000 kW) "turnkey" installations supplied
Ecolaire Canada Ltd. 41 Ardelt Place Kitchener, Ontario N2C 2C8	Trash Racks, Stoplogs, Radial Roller Type Gates, Guides and Hoists
Flygt Canada 108 Skyway Avenue Rexdale, Ontario M9W 4Y9	Turbines: Pelton (50 kW to 600 kW) Generators: Epicyclic Gear
Galt Energy Systems Ltd. 73 Water St. North Cambridge Place, Unit 502 P.O. Box 1354 Cambridge, Ontario N1R 7G6	Turbines: Francis, Kaplan, Galt design (20 kW plus) "turnkey" installations supplied
Hayward Tyler 1 Vulcan Street Rexdale, Ontario M9W 1L3	Turbines: Pelton, Reverse Pump (10 kW to 5,000 kW)
Hodgsons Steel and Iron Works Ltd. 5580 Kalar Road Niagara Falls, Ontario L2E 6S4	Penstocks: Metal (diameter 15 cm plus; length 1 m plus)
Ingersoll-Rand Canada 255 Lesmill Road Toronto, Ontario M3B 2V1	Turbines: Francis (50 kW to 20 MW)

FIRM	TYPE OF EQUIPMENT
Leroy Somer Canada Ltd. 925 Leroy Somer Blvd. Granby, Québec J2J 1E9	Turbines: Kaplan, Pelton (5 kW to 500 kW) Generators: Parallel Gear, Epicyclic Gear
Nova Energy Limited 40 Wright Ave. Dartmouth, Nova Scotia B3B 1G6	Turbines: Propeller (5 kW to 1,000 kW)
Reliance Electric Ltd. 678 Erie Street Stratford, Ontario N5A 6W1	Generators: Parallel Gear, Right Angle Gear, Epicyclic Gear Belt Drive, Rim Type
Sleegers Machining & Fabricating Inc. 649-3rd Street London, Ontario N5V 2C1	Penstocks: Metal (diameter 50 cm plus; length 1.5 m plus)
Solace Energy Centre Inc. 4025 Hastings St. East Burnaby, B.C. V5C 2J1	Turbines: Cross Flow, Kaplan Pelton (1 kW to 500 kW)
Stapenhorst Turbines 19 Libersan Crescent Dollard des Ormeaux, Québec H9A 2B4	Turbine: Cross Flow (1.5 kW to 1,200 kW) Generators: Parallel Gear, Belt Drive
Waterwheel Erectors Ltd. P.O. Box 246 Welland, Ontario L3B 5P4	Turbines: Propeller (100 kW to 2,000 kW) Turbine Repair -- all types/sizes

STREAMS OF POWER

Throughout North America there are tens of thousands of sites with potential for small scale hydro electric systems. While many of these are not large enough for development by utilities, they can be successfully utilized by homeowners, farmers, businesses, or even small communities.

Streams of Power is written for those who think they have an appropriate site and would like to take the next steps.

Chapters cover such topics as; site evaluation, various technical options, and an assessment of the project's feasibility. In addition, the procedures required in the approvals process are outlined in detail. Several appendices provide contact names and addresses, equipment manufacturers and a guide to evaluating tables and charts.